July 2002

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Kazakhstan

Kazakhstan is important to world energy markets because it has significant oil and natural gas reserves. As foreign investment pours into the country's oil and natural gas sectors, the landlocked Central Asian state is beginning to realize its enormous production potential. With sufficient export options, Kazakhstan could become one of the world's largest oil producers and exporters in the next decade.

Note: Information contained in this report is the best available as of July 2002 and is subject to change.

GENERAL BACKGROUND

Kazakhstan, the largest of the former Soviet Central Asian republics, emerged as an independent country following the 1991 collapse of the Soviet Union. Following several years of economic contraction in the early 1990's, Kazakhstan, which is heavily dependent on oil revenues, posted its first economic growth in 1996-1997, only to fall into recession again in 1998 due to the effects of the August 1998 financial crisis in Russia and slumping world oil prices. However, the recovery of world oil prices in 1999-2000, combined with a well-timed devaluation of the country's currency, the *tenge*, pulled the economy out of recession.

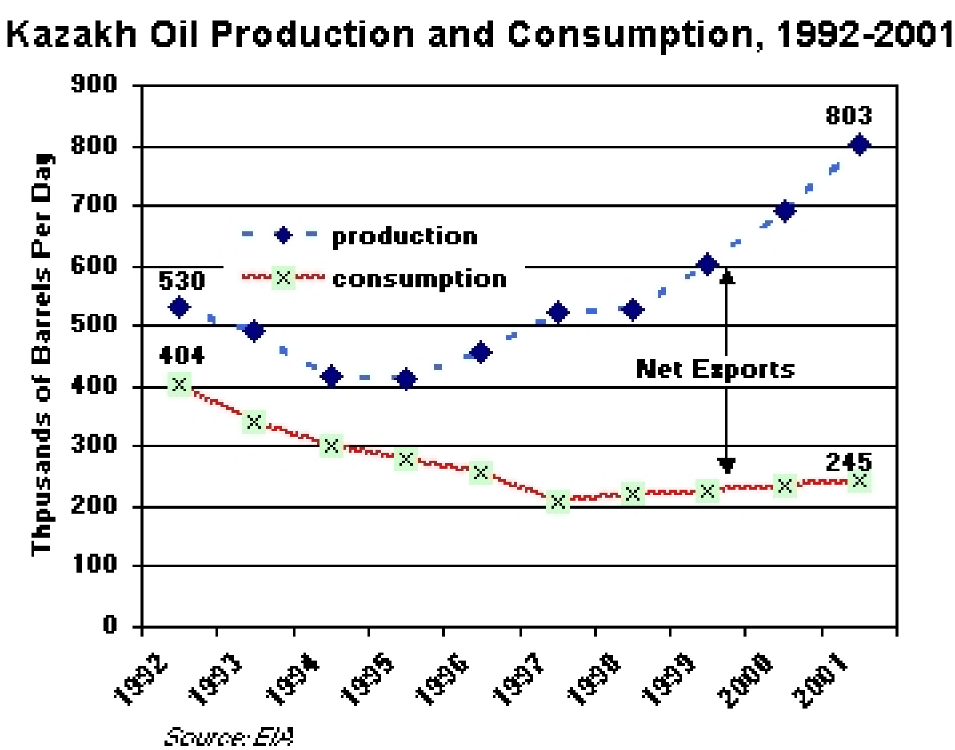
Kazakhstan has experienced impressive economic growth over the past three years, buoyed by increased oil exports, as well as by prudent fiscal policies and economic initiatives that were instituted in 1999. The results included a sharp reduction of inflation, which dropped to just 6.6% in 2001, a budget surplus, a stable currency, and a decreasing unemployment rate (3.3% in 2001). After posting moderate growth of 2.7% in 1999 as a whole, Kazakhstan's real gross domestic product (GDP) rose 9.8% in 2000, which was three times higher than the official government projection at the beginning of the year.

In 2001, Kazakhstan built on the previous year's economic performance by increasing its real GDP by an additional 13.2%, easily the country's best year of economic performance since independence. Kazakhstan's real GDP is expected to increase an additional 7% in 2002. The main driver behind Kazakhstan's economic growth has been foreign investment, mainly in the country's booming oil and natural gas industries. Since independence from Soviet rule in 1991, Kazakhstan has received approximately $13 billion in foreign investment in its oil and natural gas industries. According to Kazakh Minister of Economy and Trade Zhaksibek Kulekeyev, the oil industry currently accounts for approximately 30% of Kazakhstan's government budget revenue, and oil accounts for half of Kazakhstan's exports.

In January 2001, Kazakh President Nursultan Nazarbayev issued a decree establishing the National Fund to make the country less exposed to changing prices for energy and commodities exports. The National Fund, which received $660 million from U.S. oil major Chevron (now ChevronTexaco) in exchange for Kazakhstan's 5% stake in a joint venture at the giant Tengiz oil field, will be replenished with extra budget revenues, taxes from oil companies, and signing bonuses and royalties paid by foreign partners in joint ventures.

In February 2002, President Nazarbayev decreed the formation of Kazmunaigaz, a new national oil and natural gas company. According to Kazakh officials, the main aim of establishing Kazmunaigaz, which was formed through the merger of state oil company Kazakhoil and the national oil and gas transportation firm TransNefteGaz, is to ensure a single state policy on using the country's mineral resources. Kazakhstan also is looking to its new national energy company to compete with foreign energy companies as the massive untapped oil and natural gas reserves in the Kazakh sector of the Caspian Sea begin to be exploited.

OIL



After Russia, Kazakhstan was the second largest oil-producing republic in the former Soviet Union at the time of its collapse, with production of over half a million barrels per day (bbl/d) in 1991. Kazakhstan has significant petroleum reserves, with proven reserves estimated at 5.4 billion barrels of oil. In addition, Kazakhstan's possible hydrocarbon reserves, both onshore and offshore, dwarf its proven reserves, with estimated possible reserves--mostly in the Kazakh sector of the

Caspian Sea--of between 30 billion and 50 billion barrels. Kazakh officials have said that the offshore Kashagan field alone may contain up to 50 billion barrels of oil.

Following its independence in 1991 Kazakhstan opened up its oil sector to investment and development by foreign energy companies. International projects have taken the form of joint ventures with Kazakhoil (now Kazmunaigaz), the national oil company, as well as production-sharing agreements (PSAs), and exploration/field concessions. Although Kazakhstan's oil production dropped to just 415,000 bbl/d in the first few years after the collapse of the Soviet Union, the massive level of foreign investment into Kazakhstan's oil sector over the past 11 years has helped the country boost its oil production from 530,000 bbl/d in 1992 to 811,000 bbl/d in 2001.

Kazakhstan's oil production has doubled in just the past six years. Output has been increasing by approximately 15% per year since 1998, and the country is expected to produce over 900,000 bbl/d in 2002. From January 2002 through May 2002, Kazakh production of oil and gas condensate totaled 18.52 million tons (892,600 bbl/d), a 12.4% increase from the same time period in 2001. In addition, with a number of major oil fields recently coming onstream, including North Buzachi, Sazankurak, Saztobe, Chinarevskoye, and Airankol, and fields such as Alibekmola, Urikhtau, and Kozhasai set to begin producing shortly, Kazakhstan will increase its oil production significantly in the next decade. Kazakh oil production is expected to reach 1.2 million bbl/d in 2005, 2 million bbl/d by 2010, and as much as 2.5 million bbl/d by 2015.

Most of this growth will come from three enormous fields: Tengiz, Karachaganak, and Kashagan. The Tengiz field, with six to nine billion barrels of estimated oil reserves, is being developed by the Tengizchevroil joint venture. In April 1993, Chevron (now ChevronTexaco) concluded a $20 billion agreement with the Kazakh government to form the Tengizchevroil joint venture to develop the Tengiz field. Production at the field has increased from 25,000 bbl/d in 1993 to slightly over 250,000 bbl/d in mid-2002.

ChevronTexaco plans to invest $3 billion over the next three years to expand TCO's production capacity. Tengizchevroil is expected to increase production to 400,000 bbl/d by 2005 and, given adequate export outlets, the joint venture could reach peak production of 750,000 bbl/d by 2010.

The Karachaganak field, which is being developed by Karachaganak Integrated Organization (KIO), a consortium led by Britain's BG and Agip (Italy), has estimated reserves of 2.3 billion barrels of oil and gas condensate, as well as 16 trillion cubic feet (Tcf) of natural gas. In 1997, KIO signed an $8 billion production sharing agreement to develop the Karachaganak field for 40 years, with a planned investment of $4 billion by 2006. Thus far, the development program has focused on producing gas condensate; in the first five months of 2002, the Karachaganak field was producing 99,685 bbl/d of liquid hydrocarbons, with production scheduled to increase to between 180,000 bbl/d and 240,000 bbl/d of condensate annually during the next two years.

Although work on the offshore Kashagan field is still in the exploration stage, preliminary drilling results indicate that the field is huge, and analysts have been hailing the field as the largest oil discovery in the world in the past 30 years. In February 2001, Italy's ENI, Agip's parent company, won a fiercely contested battle among partners in the Offshore Kazakhstan International Operating Company (OKIOC) to be the operator for the field. OKIOC was subsequently renamed the Agip Kazakhstan North Caspian Operating Company (Agip KCO).

In March 2001, Agip KCO discovered oil in Kashagan West 1, a well located 25 miles from the first well drilled (Kashagan East 1). Although Agip KCO released estimates in June 2002 that the Kashagan field holds between seven and nine billion barrels of crude in proven reserves, as well as 38 billion barrels in probable reserves, both Kazakh officials and energy analysts have called that estimate "conservative." Output at the first stage of development, planned for 2005, is expected to be 100,000 bbl/d, and further development likely will catapult Kazakhstan into the top five oil producers in the world. However, Kazakhstan needs to resolve two major issues--Caspian ownership rights and export routes--before it can reach its full oil-producing potential.

Caspian Sea Issues
According to Kazakh Prime Minister Imangali Tasmagambetov, up to $120 billion could be invested in Kazakhstan's sector of the Caspian Sea over the next 10 years. Development of the offshore potential of Kazakhstan in the Caspian Sea has been slowed, however, by the ongoing dispute among the littoral states over ownership rights. This disagreement ties in with a broader debate between the Caspian Sea states over how the sea should be treated under international law and how to protect its fragile environment while exploiting its oil and natural gas resources.

Kazakhstan already has signed bilateral agreements with Turkmenistan, Azerbaijan, and Russia, pledging to divide their sections of the Caspian along median lines. However, in July 2001, an Iranian gunship forced a British Petroleum (BP) exploration vessel out of waters claimed by Iran but licensed to BP by Azerbaijan, heightening tensions and highlighting the need for a multilateral agreement. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status. Nevertheless, Kazakhstan and Russia recently agreed on a plan to develop jointly the disputed Kurmangazy field, and Kazakhstan is proceeding with development of its sector of the Caspian.

Oil Exports
The other major issue is the development of export routes to bring landlocked Kazakh oil to world markets. During the Soviet era, Kazakhstan's oil pipelines were integrated with Russia's, and all of Kazakhstan's oil was exported through the Russian pipeline system. Kazakhstan's net oil exports rose to 631,000 bbl/d in 2001, but the country's remoteness from world markets, along with its lack of export pipelines, has hindered the further growth of exports. In 2001, the majority of Kazakh oil exports was shipped by pipeline,

mainly via the Atyrau-Samara pipeline through Russia, with additional supplies shipped by rail and by barge across the Caspian Sea.

Kazakhstan took a major step towards increasing its oil exporting potential in March 2001 with the launch of the 990-mile Caspian Pipeline Consortium (CPC) pipeline. The $2.5 billion, 1.34 million-bbl/d-capacity pipeline will allow Kazakhstan to pipe its oil directly from the Tengiz field to Russia's Black Sea port of Novorossiisk. The first oil from the pipeline was scheduled to be loaded in June 2001, but several customs problems and technical hitches caused delays. After Russia and Kazakhstan reached agreement on transit tariffs for the pipeline, the first crude oil was loaded onto a tanker in Novorossiisk on October 15, 2001, and the pipeline was officially opened on November 27, 2001.

In addition to the CPC pipeline, several additional oil export pipeline routes from the Caspian Sea region are under consideration or in development. Kazakh President Nursultan Nazarbayev has expressed support for the Baku-Ceyhan Main Export Pipeline, but the country has not officially pledged to use the pipeline, preferring to keep its export options open. Kazakhstan and Iran have begun oil swaps and discussed a pipeline connecting the two countries, and in June 2002 Kazakhstan and Russia signed a 15-year oil transit agreement under which Kazakhstan will export at least 350,000 bbl/d of oil annually via the Russian pipeline system.

Downstream/Refining

Kazakhstan has three major oil refineries supplying the northern region (at Pavlodar), western region (at Atyrau), and southern region (at Shymkent), with total refining capacity of 427,000 bbl/d. The refinery at Pavlodar is supplied mainly by a crude oil pipeline from western Siberia (since Russian reserves are well placed geographically to serve that refinery), the Atyrau refinery runs solely on domestic crude from northwest Kazakhstan, and the Shymkent refinery currently uses oil from Kazakh fields at Kumkol, Aktyubinsk, and Makatinsk, although it is linked by pipeline to Russia.

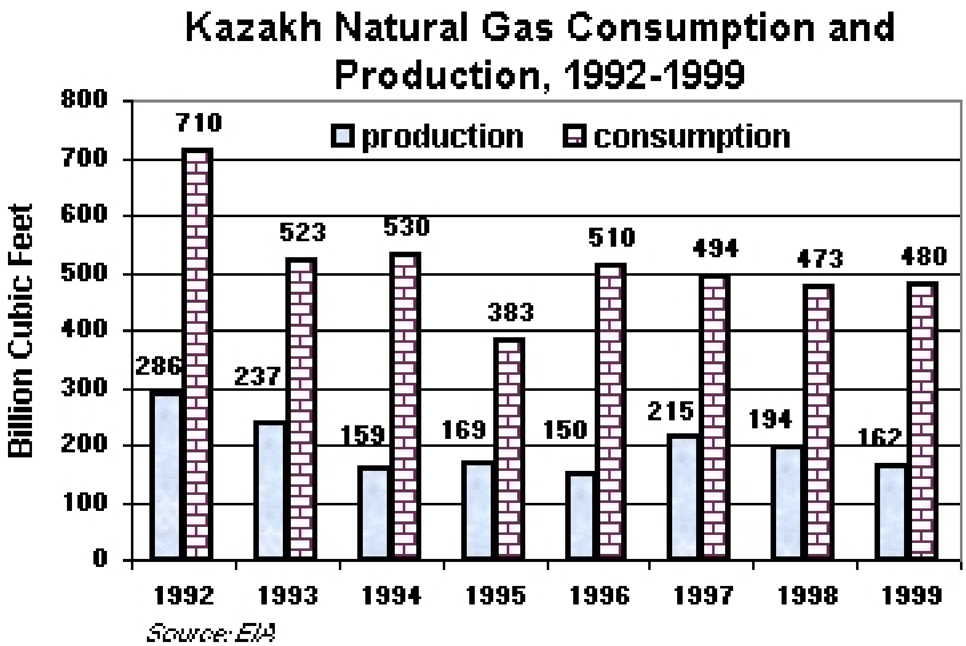
In January 2002, Kazakhstan gave the Marubeni Corporation, in collaboration with the Japan Gas Corporation, the go-ahead to carry out modernization work at the Atyrau oil refinery. Marubeni already has carried out a feasibility study for the project under an understanding signed with the Kazakhstan government in May 1998 and financed by the Japan Bank for International Cooperation. No timetable has been set yet for the renovation.

In the first two months of 2002, Kazakhstan's refineries processed 1.19 million tons of oil (an average of approximately 143,388 bbl/d), up 2.9% from the same time period in 2001. The Pavlodar refinery processed an average of 38,353 bbl/d (a 28.4% year-on-year increase), the Atyrau refinery handled 27,316 bbl/d (down 29.2%), and the Shymkent facility refined approximately 78,104 bbl/d (a 9.6% year-on-year increase). The three refineries produced 30,075 bbl/d of gasoline (an increase of 15.2% year-on-year) during this period, 40,739 bbl/d of diesel fuel (a 12% increase), and 34,955 bbl/d of fuel oil (a 14.4% decrease year-on-year).

NATURAL GAS

Kazakhstan has proven reserves of 65 trillion cubic feet (Tcf) of natural gas, ranking it in the top 20 countries in the world in terms of natural gas reserves. However, the country's natural gas industry is significantly underdeveloped, and the sector's further development is hampered by a lack of infrastructure. Kazakhstan's natural gas deposits are mainly located in the western part of the country, while the potential consuming areas are in the south and north. The lack of internal pipelines connecting the country's natural gas-producing areas to the industrial belt between Almaty and Shymkent has hampered Kazakh natural gas production, with many oil producers flaring the natural gas instead of using it.

More than 40% of Kazakhstan's proven natural gas reserves are located in one field, the giant Karachaganak field in the northwest near the border with Russia. Kazakhstan's other significant natural gas deposits include the Tengiz, Zhanazhol, and Uritau fields, and many of the undeveloped offshore areas--including the massive Kashagan field--also are believed to hold large amounts of natural gas. Although the international consortium developing Karachaganak has concentrated mainly on producing gas condensate thus far, the field yielded 132 Bcf of natural gas in 2001. Through the first five months of 2002, the Karachaganak Integrated Organization extracted an additional 68.8 Bcf of natural gas from the field.



In order to remove disincentives to the development of the country's natural gas industry, in August 1999 the Kazakh government passed a law requiring subsoil users (such as oil companies) to include natural gas utilization projects in their development plans. As a result, in 2000, Kazakhstan increased its natural gas production to 314 billion cubic feet (Bcf), the highest level in the past decade. According to preliminary 2001 figures, Kazakhstan produced 324 Bcf of natural gas in 2001, a 3.1% increase over 2000. From January 2002 through May 2002, Kazakh natural gas production totaled 158.5 Bcf, a 2.1% year-on-year increase from the same time period in 2001.

Natural Gas Distribution

Kazmunaigaz, the new state oil and natural gas company, is now the operator of Kazakhstan's main natural gas pipelines. The company, which took over the assets of KazTransGaz when it was created in February 2002, owns over 5,400 miles of trunk pipelines, as well as 26 compressor stations with 308 gas transportation units. Since Kazakhstan is such a large, sparsely populated country, it has two separate domestic natural gas distribution networks, in the west and in the south.

However, due to the lack of a pipeline linking the natural gas fields in the western part of the country to consumers in the south, the southern areas of Kazakhstan are almost completely dependent on imported supplies. Although Kazakhstan is considering the construction of an internal pipeline to link its natural gas-producing and consuming areas, the prohibitive cost (at least $1 billion) of such a pipeline has delayed any decision to go ahead with the project.

Kazakhstan invested around $120 million to upgrade its natural gas pipeline network in 2001, including about $10 million in meters for regional systems, regular maintenance, personnel training, and new equipment. KazTransGaz began restoration work on the southern natural gas pipeline system in 2001, including repairing 24 miles of pipelines and modernizing 23 wells at the Poltoraskoye underground natural gas storage facility.

Natural Gas Imports

With 2000 natural gas consumption of 491 Bcf, Kazakhstan currently imports around 35% of its natural gas needs, mainly from Uzbekistan, but with a small amount from Russia as well. The southern region of the country--from Shymkent to the former capital of Almaty--receives its natural gas supplies from Uzbekistan via the Tashkent-Bishkek-Almaty pipeline. This pipeline snakes through Uzbekistan before reaching Shymkent, then transits Kyrgyzstan and terminates in Almaty.

Kazakhstan's dependence on imported natural gas for its southern regions has been problematic during the past two winters, when erratic pricing and supplies from Uzbekistan, combined with illegal tapping of the pipeline by Kyrgyzstan, resulted in significant supply disruptions to Almaty in the middle of the heating season. As a result, Kazakhstan is dermined to end its dependence on imported supplies for its southern regions.

Kazakhstan is pinning its hopes on the development of the Amangeldy and other gasfields in southern Kazakhstan. The Amangeldy and nearby Ayrykty fields in the Zhambyl region of southern Kazakhstan have estimated natural gas reserves of more than 777 Bcf, which would be enough to provide uninterrupted natural gas supplies to the southern regions of the country for at least 12 years. Kazakhstan started work at the Amangeldy deposit in the spring of 2001, and began drilling the first of four wells in August 2001. Complete development of the field will cost approximately $770 million, with production set to begin at the start of 2003. Kazakh officials hopes to become independent of Uzbek natural gas supplies by 2005.

Natural Gas Exports

Until recently, Kazakhstan has been limited in its ability to export its natural gas, since the country's natural gas fields were not linked to Russia's natural gas pipeline system. However, as investment continues to pour into the Kazakh natural gas sector, the country's natural gas production is set to increase dramatically, and provided that the necessary infrastructure is built, Kazakhstan soon could become a major natural gas exporter.

In August 2001, the Kazakh Ministry for Energy and Mineral Resources approved a 15-year strategy for developing the country's natural gas sector that would increase natural gas production fivefold. According to the strategy, which the Kazakh government approved, Kazakhstan is aiming to increase its natural gas production to 1.2 Tcf by 2005, to 1.66 Tcf by 2010, and to 1.84 Tcf by 2015. Key to this strategy is the development of natural gas reserves at Kashagan, Karachaganak, and Tengiz.

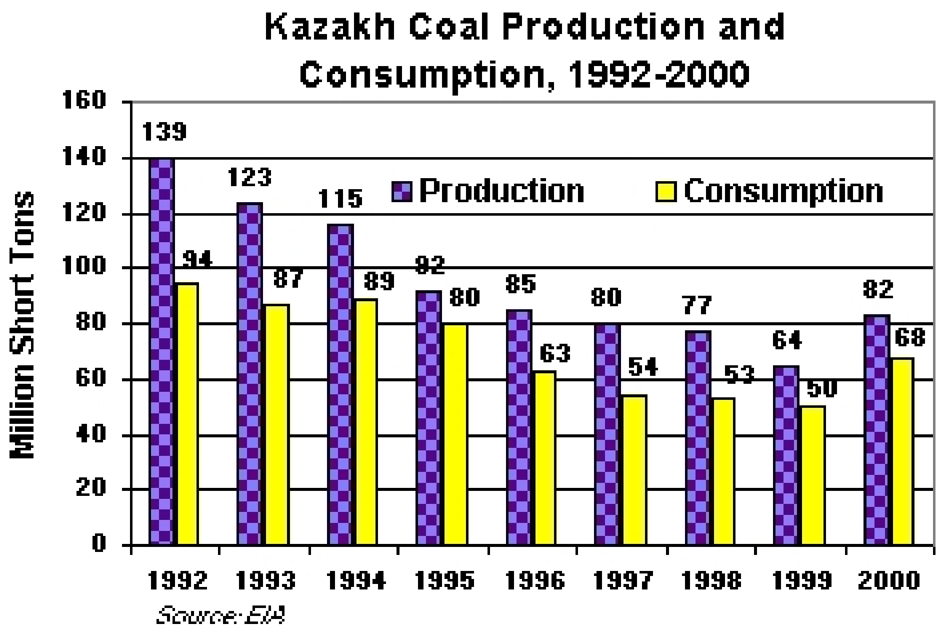
With domestic natural gas demand expected to remain stable, Kazakhstan will be able to increase its natural gas exports to nearly 1.2 Tcf by 1015, according to Uzakbai Karabalin, deputy minister of energy and mineral resources. In June 2002, Kazmunaigaz and Russia's Gazprom created KazRosGaz, a joint venture that will allow Kazakhstan to pipe its natural gas through the Russian pipeline system for the first time. According to Russian officials, KazRosGaz will have the ability to transport 125 Bcf of Kazakh natural gas via Russia, increasing up to 1.77 Tcf in the future.

Since Kazakh natural gas is a potential competitor with Russian natural gas, several new natural gas export pipelines from the Caspian Sea region also are in development or under consideration, potentially opening up new markets for Kazakh natural gas. In the meantime, Kazakhstan serves as an important natural gas transit center for Turkmen and Uzbek natural gas that is piped to Russia and beyond.

COAL

Despite a contraction of the industry since the breakup of the Soviet Union, Kazakhstan remains a major coal producer, consumer, and exporter. Kazakhstan was the third largest coal producer in the Soviet Union, trailing only Russia and Ukraine in total output. Between 1992 and 1999, however, Kazakh coal production, which is centered in the Karaganda and Ekibastuz basins, declined 54%, from 139.5 million short tons (Mmst) to 64.3 Mmst. Coal production declined in large part because of nonpayment by customers and the lack of incentives to export to Russia (due to high rail tariffs for transporting coal within Russia), as well as due to the collapse of domestic demand.

After nearly a decade of decline, Kazakh coal production increased to approximately 82.4 Mmst in 2000. According to Kazakhstan's official state statistics agency, Bogatyr Access Komir (BAK), the country's main coal mining enterprise that is a subsidiary of Access Industries, Inc. (U.S.), maintained its coal production level from 2000 in 2001, with production of about 35 Mmst of coal at the Bogatyr and Severny coal fields in northern Kazakhstan. Maikuben-Vest, which mines coal in the Pavlodar region, produced 1.99 Mmst of brown coal in the first ten months of 2001, 57.6% more than in the same period of 2000. Through the first six months of 2001, the Vostochny strip mine increased production 25.2% year-on-year, to 9 Mmst.



Coal accounted for about half of all primary energy consumption in Kazakhstan during the 1990's. From 1992 to 1999, Kazakhstan's coal consumption fell nearly 47%--from 94.2 Mmst to 50.3 Mmst. In 2000, the country's coal consumption increased for the first time since Kazakhstan's independence, with robust economic growth contributing to a 34% increase in coal consumption, to 67.6 Mmst.

Coal Exports

Kazakhstan's net coal exports to other former Soviet republics declined by two-thirds from 1991 to 1995 before making a modest recovery from 1996 to 2000. This decline in markets forced a severe cut in both coal production from Karaganda, which has a number of underground mines that produce high-quality coking coal. The high cost of extraction, combined with the drop in demand, forced a number of mines to close between 1991 and 1997. However, mines in Ekibastuz, the largest-producing area in Kazakhstan and the third largest coal basin in the former Soviet Union, have remained open and competitive after being privatized.

Kazakhstan is still the largest exporter of coal to the other former Soviet republics, accounting for almost half of the coal shipments among the republics. Russia remains the largest importer of Kazakh coal, followed by Ukraine. The Russian utilities Sverdlovskenergo and Chelyabenergo are major consumers of sub-bituminous coal from the Ekibastuz basin, and Sverdlovskenergo likely will continue to import coal from Kazakhstan since it acquired two Kazakh mines in 1996 as payment for unpaid debts for power supplied to Kazakhstan. In March 2001, Russia announced plans to import between 30 Mmst to 40 Mmst of coal from Kazakhstan per year, possibly more, depending on the scale of Russia's economic growth.

With the recent move to cash payments for coal, some potential consumers of Kazakh coal have turned out to be insolvent. Nevertheless, in August 2001, Kazakh officials announced plans to increase the country's annual coal production to over 95 Mmst by 2005, of which about 60 Mmst will be used domestically and over 30 Mmst will be exported. BAK plans to produce 40 Mmst of coal in 2002 and 50 Mmst by 2005.

ELECTRICITY

Kazakhstan has 71 power plants, including five hydroelectric power stations, giving the country an overall installed generating capacity of 17.3 gigawatts (GW). Most of Kazakhstan's power plants are combined heat and power plants, approximately 70% of which use coal, 15% natural gas, and the remaining 15% hydroelectric power. Much of the country's electricity is generated by coal-fired plants that burn a dirty, high-ash coal, and the majority of the country's electric-generating equipment is old, inefficient, and lacking in modern pollution controls.

Sectoral Reform

Following the collapse of the Soviet Union in 1991, state-run Kazakhstanenergo inherited responsibility for operating the country's power-generating facilities and its 15 separate regional electricity distribution networks. As part of Kazakhstan's move to a market-based economy, in July 1997 Kazakhstanenergo was divested of its power generation facilities, creating independent generating companies, and then renamed the Kazakhstan Electricity Grid Operating Company (KEGOC).

Since then, in an effort to increase the efficiency of the power sector, Kazakhstan has privatized all of its power plants, but the sale of regional electricity distribution companies has proceeded more slowly, and the majority of the distribution networks have not yet been privatized. KEGOC has granted management rights to several private companies, but KEGOC maintains control over high-voltage transmission lines, substations, and the central dispatching apparatus.

Non-payment of electricity bills, an inadequate collection system, and the lack of market-based transportation tariffs have been obstacles to further large-scale investment in Kazakhstan's transmission and distribution sector. Under the former Soviet system, Kazakhstan utilized a system of fixed electricity tariffs that were unrelated to production costs and investment needs. Kazakhstan's State Anti-Monopoly Committee is working to bring electricity tariffs in line with those in other countries and to allow the market to determine transmission tariffs. Effective July 1, 2001, KEGOC increased electricity transmission rates across the country by an average of 23.7%.

Power Generation and Consumption
After seven consecutive years of declining electricity production, in 2000 Kazakhstan generated 48.7 billion kilowatt-hours (Bkwh) of power, an 8% increase over 1999. Likewise, Kazakhstan's overall electricity consumption plummeted from 86.2 Bkwh in 1992 to 44.8 Bkwh in 1999, primarily due to a drop in demand from the industrial sector as output fell after independence. Owing to robust economic growth, Kazakh electricity consumption in 2000 rose 7.8% to 48.3 Bkwh. Kazakhstan's industrialized north produces about 80% and consumes about 70% of the country's electricity.

Although Kazakhstan technically generates enough electricity to meet its demand, the country has suffered from frequent power shortages since 1992 due to the sector's deteriorating infrastructure. Kazakhstan incurs large energy losses during transmission and distribution over its 285,000 miles of distribution lines. According to Kazakh Minister of Energy and Natural Resources Vladimir Shkolnik, an average of 15% of the electricity generated in Kazakhstan is lost before it reaches consumers, owing to the widespread deterioration of Kazakhstan's power infrastructure.

Transmission and Distribution
The power grids in northern Kazakhstan began to work parallel to Russia's

Unified Energy Systems in 1999 and later with the Unified Energy System of Central Asia (which also includes Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan) to solve the problem of uneven energy distribution in Kazakhstan. In January 2002, Kazakhstan withdrew from the Unified Energy System of Central Asia, citing a lack of formal agreement governing the system, but the country rejoined in April 2002 after signing five bilateral agreements with the other countries.

KEGOC estimates that it needs $258 million to reconstruct its electricity networks and overhaul its switching equipment in order to improve the reliability of its electricity supply, and to develop the power market through a power pool and improved access to the transmission network. In 1999, the World Bank's International Bank for Reconstruction and Development agreed to extend a $140 million loan to the government of Kazakhstan and KEGOC toward this electricity transmission rehabilitation project. Additional financing will be provided by KEGOC ($62.4 million) and the European Bank for Reconstruction and Development ($56 million). The U.S. Agency for International Development also is assisting Kazakhstan to develop a power pool for the regional distribution companies.

Since Kazakhstan's southern regions are largely dependent on expensive imported electricity supplies, KEGOC is considering building a second North-South power line to complement the existing, 600-MW-capacity line, making it possible to supply the country's southern regions fully with energy generated in Kazakhstan. The line would cost an estimated $300 million to build. In addition, Kazakhstan has made plans to construct five new combined heat and power stations: the 150-MW Uralskaya TETS, the 450-MW Aktyubinskaya TETS, the 300-MW Mainakskaya GES, the 1,280-MW Yuzhno-Kazakhstanskaya TETS, and the 500-MW Zapadno-Kazakhstanskaya TETS-1.

Nuclear Power

Kazakhstan's sole nuclear power plant--the 90-MW Mangyshlak Nuclear Power Plant at Aqtau--was shut down in April 1999 after nearly 26 years in operation. In September 2000, the Kazakh government shelved plans to build a 640-MW nuclear plant in the east near Lake Balkash, citing cost and safety concerns, as well as public opinion opposed to the nuclear plant. Currently there are no plans to build any new nuclear plants in Kazakhstan.

COUNTRY OVERVIEW
President: Nursultan Nazarbayev (chairman of the Supreme Soviet from February 22, 1990; elected president December 1, 1991; re-elected to a seven-year term on January 10, 1999)
Prime Minister: Imangali Tasmagambetov (since January 2002)
Independence: December 16, 1991; National holiday: Republic Day, October 25, 1990 (date on which Kazakhstan declared its sovereignty)
Population (7/01E): 16.7 million
Location: Central Asia, bordering the Caspian Sea, Russia, Turkmenistan, Uzbekistan, Kyrgyzstan, and China
Size: 1,052,100 sq. miles (slightly less than four times the size of Texas)
Major Cities: Almaty; Astana (capital, moved from Almaty in December 1998); Karaganda; Shymkent
Languages: Kazakh (Qazaq, state language) 40%, Russian (official, used in everyday business) 66%
Ethnic Groups (1999E): Kazakh (Qazaq) 53.4%, Russian 30%, Ukrainian 3.7%, Uzbek 2.5%, German 2.4%, Uighur 1.4%, other 6.6%
Religions: Muslim 47%, Russian Orthodox 44%, Protestant 2%, other 7%

ECONOMIC OVERVIEW
Minister of Finance: Aleksandr Pavlov
Minister of Economy & Trade: Mazhit Yesenbayev
Currency: Tenge
Market Exchange Rate (7/12/2002): US $1=153.1 Tenge (KZT)
Nominal Gross Domestic Product (GDP) (2001E): $21.4 billion; **(2002E):** $22.9 billion
Real GDP Growth Rate (2001E): 13.2%; **(2002E):** 7.0%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 6.6%; **(2002E):** 5.6%

Official Unemployment Rate (2001E): 3.3%
Current Account Balance (2001E): -$1.35 billion; **(2002E): -**$1.75 billion
Major Trading Partners (1999): Russia, U.S., Uzbekistan, China, Turkey, U.K., Germany, Ukraine, South Korea
Merchandise Exports (2001E): $9.7 billion; **(2002E):** $9.8 billion
Merchandise Imports (2001E): $8.7 billion; **(2002E):** $9.3 billion
Merchandise Trade Balance (2001E): $1.0 billion; **(2002E):** $0.5 billion
Major Exports: oil, ferrous and nonferrous metals, machinery, chemicals, grain, wool, meat, coal
Major Imports: machinery and parts, industrial materials, oil and gas, vehicles
External Debt (12/01E): $13.8 billion

ENERGY OVERVIEW
Minister of Energy & Natural Resources: Vladimir Shkolnik
Chairman, Kazmunaigaz (National Oil & Natural Gas Company): Lyazzat Kiinov
Proven Oil Reserves (1/1/02E): 5.4 billion barrels
Oil Production (2001E): 811,000 bbl/d, of which 704,200 bbl/d was crude; **(2002E):** 887,900 bbl/d
Oil Consumption (2001E): 180,000 bbl/d
Net Oil Exports (2001E): 631,000 bbl/d
Crude Oil Refining Capacity (1/1/02E): 427,000 bbl/d
Natural Gas Reserves (1/1/02E): 65 trillion cubic feet
Natural Gas Production (2000E): 314.3 billion cubic feet (Bcf); **(2001E):** 324 Bcf
Natural Gas Consumption (2000E): 490.9 Bcf
Net Natural Gas Imports (2000E): 176.6 Bcf
Coal Reserves (1/1/02E): 37.5 billion short tons, of which 34.2 billion is anthracite and bituminous
Coal Production (2000E): 82.4 million short tons (Mmst)
C**oal Consumption (2000E):** 67.6 Mmst
Electric Generation Capacity (2000E): 17.3 gigawatts (GW)

Electricity Generation (2000E): 48.7 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 48.3 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Natural Resources & Environmental Protection: Andar Shukputov
Total Energy Consumption (2000E): 1.79 quadrillion Btu* (0.45% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 35.0 million metric tons of carbon (0.5% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 120.2 million Btu (vs. U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 2.4 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 95,916 Btu/ $1995 (vs. U.S. value of 10,918 Btu/ $1995)**
Carbon Intensity (2000E): 1.88 metric tons of carbon/thousand $1995 (vs. U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (1998E): Industrial (52.6%), Transportation (41.8%), Residential (5.5%), Commercial (0.0%)
Sectoral Share of Carbon Emissions (1998E): Industrial (56.3%), Transportation (38.1%), Residential (5.6%), Commercial (0.0%)
Fuel Share of Energy Consumption (2000E): Coal (46.9%), Natural Gas (28.5%), Oil (18.4%)
Fuel Share of Carbon Emissions (2000E): Coal (60.3%), Natural Gas (21.2%), Oil (18.5%)
Renewable Energy Consumption (1998E): 66 trillion Btu* (6% decrease from 1997)
Number of People per Motor Vehicle (1998): 12.2 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 17th, 1995). Signatory to the Kyoto Protocol (March 12th, 1999).

Major Environmental Issues: Radioactive or toxic chemical sites associated with its former defense industries and test ranges are found throughout the country and pose health risks for humans and animals; industrial pollution is severe in some cities; because the two main rivers which flowed into the Aral Sea have been diverted for irrigation, it is drying up and leaving behind a harmful layer of chemical pesticides and natural salts; these substances are then picked up by the wind and blown into noxious dust storms; pollution in the Caspian Sea; soil pollution from overuse of agricultural chemicals and salination from poor infrastructure and wasteful irrigation practices

Major International Environmental Agreements: A party to Conventions on Air Pollution, Biodiversity, Climate Change, Desertification, Endangered Species, Ozone Layer Protection, Ship Pollution. *Signed, but not ratified:* Climate Change.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY
Organization: Kazmunaigaz (vertically-integrated state oil and natural gas company, created in February 2002 by combining state-run Kazakhoil (oil) and TransNefteGaz (oil and natural gas transport, made up of KazTransOil and KazTransGaz)); Kazakhstanugol Corporation (state coal company); Kazakhstan Electricity Grid Operating Company (KEGOC)
Major Oil and Gas Fields: Tengiz (mostly oil), Karachaganak (mostly natural gas), Kashagan (oil), Uzen, Kumkol, Korolev, Tenge, Uritau (natural gas), Zhanazhol

Major Oil Ports: Atyrau and Aqtau on the Caspian Sea
Oil Export Pipelines: Tengiz-Novorossiisk (Russia); Uzen-Atyrau-Samara (Russia); Kenkyak-Orsk (Russia) line that transports oil from the Aktyubinsk fields to the Orsk refinery
Major Oil Refineries (crude oil refining capacity): Pavlodar (162,500 bbl/d); Atyrau (104,500 bbl/d); Shymkent (160,000 bbl/d)
Major Power Plants (capacity): Ekibastuz No.1 (4,000 megawatts, MW), Yermak (2,400 MW), Zhambyl (1,230 MW)

Sources for this report include: AFX-Asia, Agence France Presse, Associated Press, BBC Monitoring Central Asia Unit, Caspian News Agency, Caspian Business Report, Central Asia & Caucasus Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, Economist Intelligence Unit ViewsWire, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Interfax News Agency, ITAR-TASS News Agency, The Moscow Times, Oil and Gas Journal, Petroleum Economist, Platt's Oilgram News, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, The Times of Central Asia, U.S. Department of Commerce's Business Information Service for the Newly Independent States (BISNIS), U.S. Department of State, U.S. Deparment of Energy, U.S. Energy Information Administration, U.S. Department of State, World Markets Online.

LINKS

For more information from EIA on the Kazakhstan, please see:
EIA: Country Information on Kazakhstan
EIA: Caspian Sea Region

Links to other U.S. government sites:
U.S. Agency for International Development

CIA World Factbook
U.S. Department of Commerce's Business Information Service for the Newly Independent States (BISNIS): Kazakhstan
U.S. Department of Commerce's Country Commercial Guide: Kazakhstan
U.S. Department of Commerce, International Trade Administration: Energy Division
U.S. Department of Commerce, Trade Compliance Center: Market Access Information
U.S. Department of Energy, Office of Fossil Energy: International Affairs
Library of Congress Country Study on the former Soviet Union
Radio Free Europe/Radio Liberty
RFE/RL: Energy Politics in the Caspian and Russia
U.S. State Department: Background Notes
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U.S. Embassy, Almaty, Kazakhstan

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January 2002

Kazakhstan

Kazakhstan is important to world energy markets because it has significant oil and natural gas reserves. As foreign investment pours into the country's oil and natural gas sectors, the landlocked Central Asian state is beginning to realize its enormous production potential. With sufficient export options, Kazakhstan could become one of the world's largest oil producers and exporters in the next decade.

Note: Information contained in this report is the best available as of January 2002 and is subject to change.

GENERAL BACKGROUND

Kazakhstan, which became independent in 1991 following the collapse of communism and the demise of the Soviet Union, has made significant economic strides over the past two years. After several years of economic contraction in the immediate aftermath of the Soviet Union's collapse, the country's economic decline halted in 1995, only to be followed by another recession in 1997-1998 due to effects of the August 1998 financial crisis in Russia, combined with slumping world prices. However, the recovery of world oil prices in 1999-2000, plus a well-timed devaluation of the country's currency, the tenge, pulled the economy out of recession.

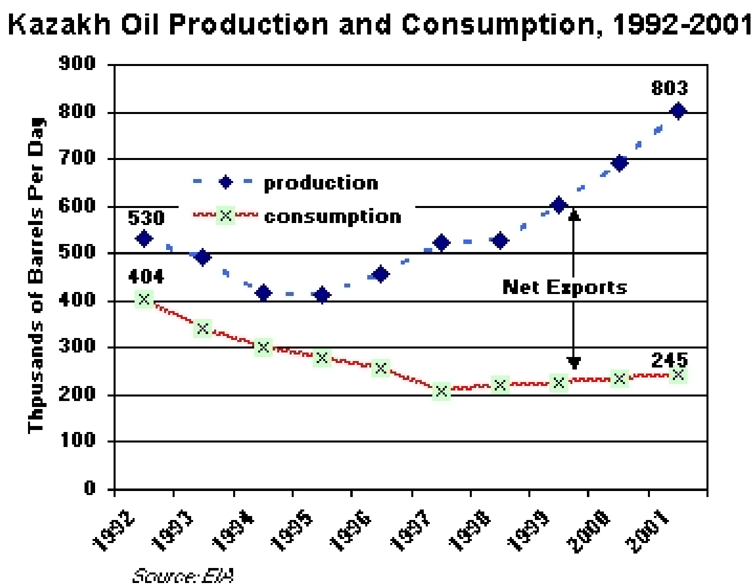
The Kazakh economy began to record high levels of growth in the second half of 1999, partly as a result of fiscal policies and economic initiatives that had been put in place. The results included a sharp reduction of inflation (below 10%), a budget surplus, a stable currency, and a decreasing unemployment rate. After posting moderate growth of 1.7% in 1999, Kazakhstan's real gross domestic product (GDP) rose by 9.8% in 2000, which was three times higher than the official government projection at the beginning of the year. In 2001, Kazakhstan built on the previous year's economic performance by increasing its real GDP by a further 13.8%, easily the country's best year of economic performance since independence.

Kazakhstan's economic growth has been driven by increased oil exports and foreign investments, mainly in the country's booming oil and natural gas industries. According to Kazakh Minister of Economy and Trade Zhaksibek Kulekeyev, the oil industry currently accounts for approximately 30% of Kazakhstan's government budget revenue, and foreign investment continues to pour into the country's potentially enormous oil and natural gas sector. Between 1991 and 2001, Kazakhstan received approximately $10 billion in foreign investment, mainly in the oil and natural gas industries, and Nurlan Balgimbayev, president of Kazakhoil, the national oil and natural gas company, said in October 2001 that the resource-rich Central Asian state planned to attract an additional $65-$70 billion in investment to its promising oil and natural gas sector over the next 10 to 20 years.

Since the country's economy is so dependent on oil revenues, in January 2001, Kazakh President Nursultan Nazarbayev issued a decree establishing the National Fund to make the country less vulnerable to changing prices for energy and commodities exports. The National Fund, which received $660 million from U.S. oil major Chevron (now ChevronTexaco) in exchange for Kazakhstan's 5% stake in a joint venture at the giant Tengiz oil field, will be replenished with extra budget revenues, taxes from oil companies, and signing bonuses and royalties paid by foreign partners in joint ventures.

OIL

Kazakhstan has significant petroleum reserves, with estimates of proven reserves ranging from 5.4 billion to 17.6 billion barrels of oil. In addition, the country's possible reserves, both onshore and offshore, dwarf proven reserves; as a result, foreign investment has poured into Kazakhstan's oil and gas sector during the past decade, helping the country boost its oil production from 530,000 barrels per day (bbl/d) in 1992 to 803,000 bbl/d in 2001, although dropping to just 415,000 bbl/d in the first few years after the collapse of the Soviet Union.



In order to reach its oil production potential, Kazakhstan has opened up its oil sector to privatization and development by foreign energy companies. International oil projects have taken the form of joint ventures with Kazakhoil, as well as production-sharing agreements (PSAs), and exploration/field concessions. With a number of major oil fields coming onstream recently, including North Buzachi, Sazankurak, Saztobe, Chinarevskoye, and Airankol, and with others such as Alibekmola, Urikhtau, and Kozhasai set to begin producing shortly, Kazakhstan is set to ramp up its oil production over the next decade. Kazakh oil production is expected to reach 925,000 bbl/d in 2002, 1.2 million bbl/d in 2005, and potentially 3 million bbl/d by 2010.

Most of this growth will come from three massive fields: Tengiz, Karachaganak, and Kashagan. The Tengiz field, with an estimated 6-9 billion barrels of recoverable oil reserves, is being developed by the Tengizchevroil joint venture. In April 1993, Chevron (now ChevronTexaco) concluded a $20 billion agreement with the Kazakh government to form the Tengizchevroil joint venture to develop Tengiz. Production at the field has increased from 25,000 bbl/d in 1993 to approximately 290,000 bbl/d in 2001. Output could increase to 415,000 bbl/d in 2005, and, given adequate export outlets, the Tengizchevroil joint venture could reach peak production of 750,000 bbl/d by 2010.

The Karachaganak field, which is being developed by Karachaganak Integrated Organization (KIO), a consortium led by Britain's BG and Agip (Italy), has estimated recoverable reserves of 2.25 billion barrels of oil and gas condensate, as well as 17.6 trillion cubic feet (Tcf) of natural gas. In 1998, the consortium kicked off a $3.5 billion, six-year program to develop the field. Thus far, the development program has focused on producing gas condensate; in 2000, the consortium produced 92,000 bbl/d of gas condensate, and 2001 totals were expected to exceed 100,000 bbl/d until production was shut in for two months in the fall of 2001 due to a dispute with Russia over the issue of taxation of gas condensate exports. Karachaganak's oil production is scheduled to increase over the next two years.

Although work on the offshore Kashagan field is still in the exploration stage, preliminary drilling results indicate that the field could be the largest oil discovery in the world during the past 40 years. In February 2001, Italy's ENI, Agip's parent company, won a fiercely-contested battle among partners in the Offshore Kazakhstan International Operating Company (OKIOC) to be the field operator. OKIOC was subsequently renamed the Agip Kazakhstan North Caspian Operating Company (Agip KCO). In March 2001, Agip KCO discovered oil in Kashagan West 1, a well located fully 25 miles from the first well drilled (Kashagan East 1). Analysts are estimating that the Kashagan field could contain up to 40 billion barrels of oil, at least 10 billion barrels of which are thought to be recoverable. Output at the first stage of development, planned for 2005, is expected to be 100,000 bbl/d, and further development likely will catapult Kazakhstan into the top five oil producers in the world.

Caspian Sea Legal Issues

Development of the offshore potential of Kazakhstan in the Caspian Sea has been slowed by a dispute among the littoral states over ownership rights. This disagreement ties in with a broader debate between Caspian Sea Region states over how the sea should be treated under international law (including environmental issues). Kazakhstan has signed bilateral agreements with Turkmenistan, Azerbaijan, and Russia pledging to divide their sections of the Caspian along median lines, but all of these agreements are interim until the status of the Caspian Sea is settled among all of the littoral states. In July 2001, an Iranian gunship forced a British Petroleum (BP) exploration vessel out of waters claimed by Iran but licensed to BP by Azerbaijan, heightening tensions and highlighting the need for a multilateral agreement. In October 2001, a planned summit of the Caspian littoral heads of state was postponed when it became apparent that no final agreement would be reached at the summit.

Oil Exports

Another major issue facing the Kazakh oil sector is the development of export routes to bring Kazakh oil to world markets from the landlocked Central Asian state. Under the former Soviet Union, Kazakhstan's pipeline network was integrated with the Russian pipeline system, and all of Kazakhstan's oil was exported through the Russian pipeline system. Kazakhstan's net oil exports rose to 558,000 bbl/d in 2001, but the country's remoteness from world markets, along with its lack of export pipelines, has hindered the further growth of exports. In 2001, the majority of Kazakh oil exports was shipped by pipeline, mainly via the Atyrau-Samara pipeline through Russia, with additional supplies shipped by rail and by barge across the Caspian Sea.

Kazakhstan took a major step towards increasing its oil exports in March 2001 with the launch of the 990-mile Caspian Pipeline Consortium (CPC) pipeline. The $2.5-billion, 1.34-million-bbl/d-capacity pipeline will allow Kazakhstan to pipe its oil directly from the Tengiz field to Russia's Black Sea port of Novorossiisk. The first oil from the pipeline was scheduled to be loaded in June 2001, but several customs problems and technical hitches caused delays. After Russia and Kazakhstan reached agreement on transit tariffs and a quality bank for the pipeline, the first crude oil was loaded onto a tanker in Novorossiisk on October 15, 2001, and the pipeline was officially opened on November 27, 2001.

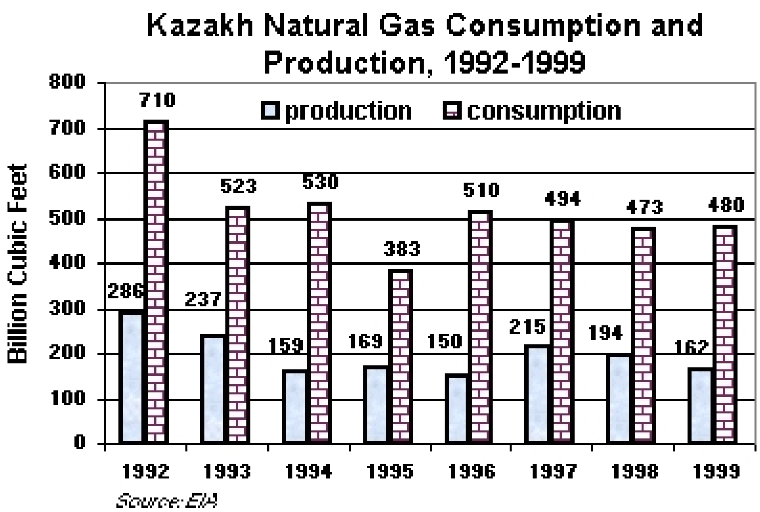
In addition to the CPC pipeline, several additional oil export pipeline routes from the Caspian Sea region are under consideration or in development. In March 2001, Kazakh President Nursultan Nazarbayev appeared to give Kazakhstan's support to the Baku (Azerbaijan)-Ceyhan (Turkey) Main Export Pipeline, saying that the first oil from the giant Kashagan field would go to the pipeline, which is slated to begin construction in 2002 and be ready by September 2004. However, Kazakhstan has not officially pledged its support for the pipeline, preferring to keep its export options open.

Downstream/Refining

Kazakhstan has three major oil refineries supplying the northern region (at Pavlodar), western region (at Atyrau), and southern region (at Shymkent), with total refining capacity of 427,000 bbl/d. The refinery at Pavlodar is supplied mainly by a crude oil pipeline from western Siberia (since Russian reserves are better placed geographically to serve that refinery), the Atyrau refinery runs solely on domestic crude from northwest Kazakhstan, and the Shymkent refinery (now Shymkentnefteorgsintez, or Shnos) currently uses oil from Kazakh fields at Kumkol, Aktyubinsk, and Makatinsk, although it is linked by pipeline to Russia.

In the first eight months of 2001, Kazakhstan's refineries processed 5.07 million tons of oil (an average of approximately 152,600 bbl/d), an increase of 22.6% from the same time period in 2000. The Pavlodar refinery processed an average of 38,257 bbl/d, the Atyrau refinery handled 45,065 bbl/d, and the Shymkent facility refined approximately 69,194 bbl/d. Fuel oil accounted for nearly 33% of the total refined products during this period, with diesel (30%) and gasoline (20%) much of the remainder. In October 2001, the Kazakh government introduced a temporary ban (until March 1, 2002) on exports of fuel oil in order to maintain sufficient reserves to meet domestic requirements.

NATURAL GAS



Kazakhstan has proven natural gas reserves of between 65 and 70 trillion cubic feet (Tcf), ranking it in the top 20 countries in the world. However, the lack of internal pipelines connecting the country's natural gas-producing areas to the industrial belt between Almaty and Shymkent has hampered Kazakh natural gas production, with many oil producers flaring the natural gas instead of using it. In 1999, Kazakhstan produced just 162 billion cubic feet (Bcf) of natural gas, down from 286 Bcf in 1992. In order to reduce the flaring of natural gas, Kazakhstan passed a new law in August 1999 requiring subsoil users (such as oil companies) to include natural gas utilization projects in their development plans.

More than 40% of the country's proven natural gas reserves are located in one field, the giant Karachaganak field in northwest Kazakhstan. In 1997, an international consortium signed a $7-$8 billion final production sharing agreement to develop the field for 40 years, with a planned investment of $4 billion by 2006. Thus far, development of the field has concentrated on gas condensate. According to the Kazakh government, in 2000 the Karachaganak field produced 4.6 million tons (92,000 bbl/d) of liquid hydrocarbons, with production eventually set to increase to 180,000-240,000 bbl/d of condensate a year. Kazakhstan's other significant producing areas include the Tengiz, Zhanazhol, and Uritau fields, with the undeveloped offshore areas also believed to hold large amounts of natural gas.

Nevertheless, because of a lack of developed pipeline infrastructure linking the natural gas fields in the western part of the country to consumers in the southern part of the country (a pipeline network connecting the two is estimated to cost over $1 billion), Kazakhstan must import natural gas to meet domestic demand. Kazakhstan's 1999 natural gas consumption of 480 Bcf, while down from the 710 Bcf consumed in 1992, still far exceeded the country's domestic production.

Natural Gas Imports

Kazakhstan currently imports over half of its natural gas consumption needs, mainly from Uzbekistan, but with a small amount from Russia as well. KazTransGaz, the state-owned joint stock company that was set up by the Kazakh government in February 2000 in a reversal of the country's natural gas sector privatization, is responsible for transporting and distributing natural gas in the country. KazTransGaz imports natural gas from Russia to supply the northern Aktyubinsk and Kustanay regions, as well as offering Kazakh natural gas from the Zhanazol and Tengiz fields.

With no pipelines linking domestic natural gas production to consumers, the southern areas of Kazakhstan are almost completely dependent on imported supplies. Instead, the region encompassing Shymkent to the former capital of Almaty receives its natural gas supplies via the Bukhara-Tashkent-Bishkek-Almaty pipeline. This pipeline snakes through Uzbekistan before reaching Shymkent, then transits Kyrgyzstan and terminates in Almaty. The problem of Kazakhstan's dependence on imported natural gas for its southern regions was brought to the fore in the winter of 2000-2001, when erratic pricing and supplies from Uzbekistan, combined with illegal tapping of the pipeline by Kyrgyzstan, resulted in significant supply disruptions to Almaty in the middle of heating season.

In March 2001, KazTransGaz suggested taking a section of the natural gas pipeline in concession for 10 years in payment for Kyrgyzstan's $5 million debt accumulated as a result of its unauthorized removal of Uzbek natural gas intended for Almaty. KazTransGaz promised to invest $2.2 million in the Tashkent-Bishkek-Almaty section of the pipeline during the first year and $1 million each subsequent year in an effort to maintain uninterrupted supplies to Almaty, the surrounding Almaty region, and part of the Zhambyl region. Kyrgyzstan balked at this idea, prompting Kazakhstan to consider investing in a 90-mile pipeline that would link to the existing pipeline and bypass Kyrgyzstan.

In July 2001, KazTransGaz and Uztransgaz, the Uzbek natural gas monopoly, reached a five-year agreement on natural gas supplies, with Kazakhstan purchasing 24.7 Bcf of natural gas for the remainder of 2001 and up to 60 Bcf in 2002, an increase from the average of approximately 44 Bcf of natural gas that Kazakhstan has imported in the past few years. In November and December 2001, however, industrial and domestic consumers in southern Kazakhstan again had their natural gas supplies interrupted due to Kyrgyzstan's illegal siphoning of nearly 15 million cubic meters (0.5 Bcf) of natural gas intended for Almaty. According to Kyrgyzgaz, the Kyrgyz gas transport company, the company took the 0.5 Bcf of natural gas without permission because Uztransgaz had failed to fulfill its commitments to supply natural gas to northern Kyrgyzstan.

Kazakhstan's growing uneasiness about Uzbek supplies, along with Kyrgyzstan's illegal tapping of the pipeline, the high cost of imports, and Kazakhstan's own natural gas-producing potential, has strengthened the country's determination to end its dependence on imported supplies for its southern regions. KazTransGaz is focusing its efforts on making Kazakhstan self-sufficient in natural gas supplies, pinning its hopes on the development of the Amangeldy and other gasfields in southern Kazakhstan. The Amangeldy and nearby Ayrykty fields in the Zhambyl region of southern Kazakhstan have estimated natural gas reserves of more than 22 Bcm (777 Bcf), which would be enough to provide uninterrupted natural gas supplies to the southern regions of the country for at least 12 years.

Kazakhstan started work at the Amangeldy deposit in the spring of 2001, and began drilling the first of four wells in August 2001. Over the next two years, KazTransGaz plans to invest more than $142 million to develop the field. Complete development of the field will cost approximately $770 million, with production set to begin at the start of 2003. Development of the Amangeldy and other natural gas fields in southern Kazakhstan will allow KazTransGaz to supply the 53 Bcf of natural gas per year that the region consumes, enabling Kazakhstan to become independent of Uzbek natural gas supplies by 2005.

Natural Gas Exports

Since Kazakhstan's natural gas fields currently are not linked to Russia's pipeline system, Kazakhstan is limited in its ability to export the natural gas it produces. However, with sufficient investment in developing the country's natural gas fields and its pipeline infrastructure, Kazakhstan's significant natural gas production potential means that the country soon could become a net natural gas exporter.

In August 2001, the Kazakh Ministry for Energy and Mineral Resources approved a 15-year strategy for developing the country's natural gas sector that would increase natural gas production tenfold. According to the strategy, which the Kazakh government approved, Kazakhstan is aiming to increase its natural gas production to 1.2 Tcf by 2005, to 1.66 Tcf by 2010, and to 1.84 Tcf by 2015. Key to this strategy is the development of natural gas reserves at Kashagan, Karachaganak, and Tengiz.

With domestic natural gas demand expected to remain stable, Kazakhstan will be able to increase its natural gas exports to nearly 1.2 Tcf by 2015, according to Uzakbai Karabalin, deputy minister of energy and mineral resources. Since Russia's Gazprom is a potential competitor with Central Asian natural gas on world markets, several new natural gas export pipelines from the Caspian Sea region are in development or under consideration, potentially opening up new markets for Kazakh natural gas. In the meantime, Kazakhstan serves as an important natural gas transit center for Turkmen and Uzbek natural gas that is piped to Russia and beyond.

COAL

Despite a contraction of the industry since the breakup of the Soviet Union, Kazakhstan remains a major coal producer, consumer, and exporter. Kazakhstan was the third largest coal producer in the Soviet Union, trailing only Russia and Ukraine in total output. Between 1992 and 1999, however, Kazakh coal production, which is centered in the Karaganda and Ekibastuz basins, declined 54%, from 139.5 million short tons (Mmst) to 64.2 Mmst. Coal production declined in large part because of nonpayment by customers and the lack of incentives to export to Russia (due to high rail tariffs for transporting coal within Russia), as well as due to the collapse of domestic demand. Kazakh coal consumption fell nearly 58%--from 94.2 Mmst to 39.5 Mmst--during the same time period.

Coal accounted for about half of all primary energy consumption in Kazakhstan during 1991-1999. In addition, net exports to other former Soviet republics declined by two-thirds from 1991 to 1995 before beginning a modest recovery from 1996 to 2000. This decline in markets forced a severe cut in coal production from Karaganda, which has a number of underground mines that produce high-quality coking coal. The high cost of extraction, combined with the drop in demand, forced a number of mines to close between 1991 and 1997. However, mines in Ekibastuz, the largest-producing area in Kazakhstan and the third largest coal basin in the former Soviet Union, have remained open and competitive because several mines have been privatized.

After nearly a decade of decline, Kazakh coal production is on the rise. After producing approximately 75 Mmst of coal in 2000, nearly a 17% increase over 1999, Kazakhstan planned to produce 80.5 Mmst of coal in 2001. According to Kazakhstan's official state statistics agency, Bogatyr Access Komir (BAK), a subsidiary of Access Industries, Inc. (U.S.) that is developing the Bogatyr and Severny coal fields in northern Kazakhstan, produced 27.95 Mmst of coal in the first ten months of 2001, down 4.3% year-on-year. Maikuben-Vest, which mines coal in the Pavlodar region, produced 1.99 Mmst of brown coal in the first ten months of 2001, 57.6% more than in the same period of 2000. Through the first six months of 2001 the Vostochny strip mine increased production 25.2% year-on-year, to 9 Mmst.

Kazakhstan is still the largest exporter of coal to the other former Soviet republics, accounting for almost half of the coal shipments among the republics. Russia remains the largest importer of Kazakh coal, followed by Ukraine. The Russian utilities Sverdlovskenergo and Chelyabenergo are major consumers of sub-bituminous coal from the Ekibastuz basin, and Sverdlovskenergo likely will continue to import coal from Kazakhstan since it acquired two Kazakh mines in 1996 as payment for unpaid debts for power supplied to Kazakhstan. In March 2001, Russia announced plans to import between 30 Mmst to 40 Mmst of coal from Kazakhstan per year, possibly more, depending on the scale of Russia's economic growth.

With the recent switch to cash payments for coal, many potential consumers are turning out to be insolvent, and as a result some production targets are not being achieved. BAK, which planned to produce 35-36 Mmst for 2001 overall, attributed its cut in production in the first ten months of 2001 to the insolvency of Russian consumers. Nevertheless, in August 2001, Kazakh officials announced plans to increase coal production to over 95 Mmst by 2005, of which about 60 Mmst will be used domestically and over 30 Mmst will be exported. BAK plans to produce 40 Mmst of coal in 2002 and 50 Mmst by 2005.

ELECTRICITY

Kazakhstan has 54 fossil-fuel powered plants and five hydroelectric power stations, giving the country an overall installed generating capacity of 17.4 gigawatts (GW). Most of Kazakhstan's electricity is generated by coal-fired plants concentrated in the north that burn a dirty, high-ash coal, and much of the country's electric-generating equipment is old, inefficient, and lacking in modern pollution controls.

Kazakhstan's power generation has experienced an annual decline since independence--the country's total 1999 generation of 44.4 billion kilowatt-hours (Bkwh) was only 56% of its 1992 level of 78.6 Bkwh. From a 1992 level of 86.2 Bkwh, Kazakhstan's electricity consumption dropped to 44.1 Bkwh in 1999, primarily due to a drop in demand from the industrial sector as output fell after independence. Kazakhstan's industrialized north consumes about 70% of the country's electricity.

Electricity Transmission and Distribution

Although Kazakhstan technically generates enough electricity to meet its demand, the country has suffered from frequent power shortages since 1992 due to the sector's deteriorating infrastructure. Kazakhstan incurs large energy losses during transmission and distribution over its 285,000 miles of distribution lines.

In addition, due to its vast, sparsely populated land area, Soviet planners developed Kazakhstan's electricity transmission and distribution system to connect to separate networks: to the Russian network in the north (to Siberian Russia) and northwest (to European Russia), and to the Central Asian network in the south (Kyrgyzstan, Turkmenistan, Tajikistan, and Uzbekistan). Following independence, state-run Kazakhstanenergo inherited responsibility for operating the country's power-generating facilities and its separate networks.

As part of Kazakhstan's move to a market-based economy, in July 1997 Kazakhstanenergo was divested of its power generation facilities and renamed the Kazakhstan Electricity Grid Operating Company (KEGOC). In an effort to upgrade the power sector, Kazakhstan has proceeded with privatization of power plants and regional electricity distribution companies, including granting management rights for the eastern network to AES (U.S.). KEGOC maintains control over high-voltage transmission lines, substations, and the central dispatching apparatus.

Non-payment of electricity bills, an inadequate collection system, and the lack of market-based transportation tariffs have been obstacles to further large-scale investment in Kazakhstan's transmission and distribution sector. Under the former Soviet system, Kazakhstan utilized a system of fixed electricity tariffs that were unrelated to production costs and investment needs. Kazakhstan's State Anti-Monopoly Committee is working to bring electricity tariffs in line with those in other countries and to allow the market to determine transmission tariffs. Effective July 1, 2001, KEGOC increased electricity transmission rates across the country by an average of 23.7%.

Upgrading the Power Sector

KEGOC needs $258 million to reconstruct its electricity networks and overhaul its switching equipment in order to improve the reliability of its electricity supply, and to develop the power market through a power pool and improve access to the transmission network. In 1999, the World Bank's International Bank for Reconstruction and Development agreed to extend a $140-million loan to the government of Kazakhstan and KEGOC toward this electricity transmission rehabilitation project. Additional financing will be provided by KEGOC ($62.4 million) and the European Bank for Reconstruction and Development ($56 million). The U.S. Agency for International Development also is assisting Kazakhstan to develop a power pool for the regional distribution companies.

In July 2001, the Asian Development Bank (ADB) approved a $150,000 technical assistance grant to Kazakhstan to prepare an energy strategy that will focus on increasing investment and expanding power supply to poor and remote areas. The ADB has also agreed to administer a $95,000 grant from the Government of Finland to support the study. The total cost of the study is $363,000, of which the Kazakhstan government will finance $118,000.

In addition, the separation of transmission networks means that Kazakhstan is both an exporter and importer of electricity in accordance with regional needs. Electricity imports from Russia and Kyrgyzstan account for over 10% of domestic consumption, with Uzbekistan also exporting small amounts of power to Kazakhstan. Payment for imported power has been an issue, and both Russian and Kyrgyz suppliers have cut power to Kazakhstan several times due to unpaid bills.

In order to reduce its dependence on expensive, imported electricity supplies, Kazakhstan has made plans to construct five new combined heat and power stations: the 150-MW Uralskaya TETS, the 450-MW Aktyubinskaya TETS, the 300-MW Mainakskaya GES, the 1,280-MW Yuzhno-Kazakhstanskaya TETS, and the 500 MW Zapadno-Kazakhstanskaya TETS-1. In addition, AES expects to receive $30 million from the EBRD to reconstruct and modernize the Ust-Kamenogorsk hydroelectric and heat and power plants and the Shulba hydroelectric plant. Also, a Kazakh-Russian joint venture was set up at Ekibastuz State Regional Power Station 2 in Pavlodar region, where one 350-MW generator is operational and a second was scheduled to be overhauled. The projected capacity of each of the generators is 500 MW.

Nuclear
Kazakhstan had one, 90-MW nuclear power plant at Aqtau on the Caspian Sea, but the plant was shut down in April 1999 after nearly 26 years in operation. The country had planned to build a new nuclear power station in the east near Lake Balkash, with three units of 640 MW each, but in September 2000 the Kazakh government rejected the blueprints and shelved the project, citing cost and safety concerns, as well as public opinion opposed to the nuclear plant.

COUNTRY OVERVIEW

President: Nursultan Nazarbayev (chairman of the Supreme Soviet from February 22, 1990; elected president December 1, 1991; re-elected to a seven-year term on January 10, 1999)
Prime Minister: Kasymzhomart Tokayev (since October 2, 1999)
Independence: December 16, 1991; National holiday: Republic Day, October 25, 1990 (date on which Kazakhstan declared its sovereignty)
Population (7/01E): 16.7 million
Location: Central Asia, bordering the Caspian Sea, Russia, Turkmenistan, Uzbekistan, Kyrgyzstan, and China
Size: 1,052,100 sq. miles (slightly less than four times the size of Texas)
Major Cities: Almaty; Astana (capital, moved from Almaty in December 1998); Karaganda; Shymkent
Languages: Kazakh (Qazaq, state language) 40%, Russian (official, used in everyday business) 66%
Ethnic Groups (1999E): Kazakh (Qazaq) 53.4%, Russian 30%, Ukrainian 3.7%, Uzbek 2.5%, German 2.4%, Uighur 1.4%, other 6.6% (1999 census)
Religions: Muslim 47%, Russian Orthodox 44%, Protestant 2%, other 7%

ECONOMIC OVERVIEW

Minister of Finance: Mazhit Yesenbayev
Minister of Economy & Trade: Zhaksibek Kulekeyev
Currency: Tenge
Market Exchange Rate (1/15/2002): US $1=158.2 Tenge
Nominal Gross Domestic Product (GDP) (2001E): $21.4 billion; **(2002E):** $22.9 billion
Real GDP Growth Rate (2001E): 13.2%; **(2002E):** 7.0%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 6.6%; **(2002E):** 5.6%
Official Unemployment Rate (2001E): 3.3%
Current Account Balance (2001E): -$1.35 billion; **(2002E):** -$1.75 billion
Major Trading Partners: Russia, U.S., Uzbekistan, China, Turkey, U.K., Germany, Ukraine, South Korea (1999)
Merchandise Exports (2001E): $9.7 billion; **(2002E):** $9.8 billion

Merchandise Imports (2001E): $8.7 billion; **(2002E):** $9.3 billion
Merchandise Trade Balance (2001E): $1.0 billion; **(2002E):** $0.5 billion
Major Exports: oil, ferrous and nonferrous metals, machinery, chemicals, grain, wool, meat, coal
Major Imports: machinery and parts, industrial materials, oil and gas, vehicles
External Debt (12/01E): $13.8 billion

ENERGY OVERVIEW

Minister of Energy & Natural Resources: Vladimir Shkolnik
Chairman, Kazakhoil National Oil & Gas Company: Nurlan Balgimbayev
Proven Oil Reserves (2002E): 5.4-17.6 billion barrels
Oil Production (2001E): 803,000 bbl/d, of which 698,000 bbl/d is crude
Oil Consumption (2001E): 245,000 bbl/d
Net Oil Exports (2001E): 558,000 bbl/d
Crude Oil Refining Capacity (1/1/2002E): 427,000 bbl/d
Natural Gas Reserves (2002E): 65-70 trillion cubic feet
Natural Gas Production (1999E): 162 billion cubic feet (Bcf)
Natural Gas Consumption (1999E): 480 Bcf
Net Natural Gas Imports (1999E): 318 Bcf
Coal Reserves (1999E): 37.5 billion short tons, of which 34.2 billion is anthracite and bituminous
Coal Production (1999E): 64.2 million short tons (Mmst); **(2000E):** 75 Mmst
C**oal Consumption (1999E):** 39.5 Mmst
Electric Generation Capacity (1999E): 17.4 gigawatts (GW)
Electricity Generation (1999E): 44.4 billion kilowatt-hours (Bkwh)
Electricity Consumption (1999E): 44.1 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Natural Resources & Environmental Protection: Andar Shukputov
Total Energy Consumption (1999E): 1.5 quadrillion Btu* (0.4% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 26.6 million metric tons of carbon (0.4% of world total carbon emissions)
Per Capita Energy Consumption (1999E): 97.5 million Btu (vs U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 1.7 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 58,392 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 1.1 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (52.6%), Transportation (41.8%), Residential (5.5%), Commercial (0.0%)
Sectoral Share of Carbon Emissions (1998E): Industrial (56.3%), Transportation (38.1%), Residential (5.6%), Commercial (0.0%)
Fuel Share of Energy Consumption (1999E): Natural Gas (34.5%), Coal (29.9%), Oil (29.5%)
Fuel Share of Carbon Emissions (1999E): Coal (40.8%), Oil (32.0%), Natural Gas (27.3%)
Renewable Energy Consumption (1998E): 66 trillion Btu* (6% decrease from 1997)
Number of People per Motor Vehicle (1998): 12.2 (vs U.S. value of 1.3)

Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 17th, 1995). Signatory to the Kyoto Protocol (March 12th, 1999).

Major Environmental Issues: Radioactive or toxic chemical sites associated with its former defense industries and test ranges are found throughout the country and pose health risks for humans and animals; industrial pollution is severe in some cities; because the two main rivers which flowed into the Aral Sea have been diverted for irrigation, it is drying up and leaving behind a harmful layer of chemical pesticides and natural salts; these substances are then picked up by the wind and blown into noxious dust storms; pollution in the Caspian Sea; soil pollution from overuse of agricultural chemicals and salination from poor infrastructure and wasteful irrigation practices

Major International Environmental Agreements: A party to Conventions on Air Pollution, Biodiversity, Climate Change, Desertification, Endangered Species, Ozone Layer Protection, Ship Pollution. *Signed, but not ratified:* Climate Change.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1998

ENERGY INDUSTRY

Organization: Kazakhoil National Oil and Gas Company; KazTransOil (state oil pipeline company); KazTransGaz (state natural gas pipeline company); Kazakhstanugol Corporation (state coal company); Kazakhstan Electricity Grid Operating Company (KEGOC)
Major Oil and Gas Fields: Tengiz (mostly oil), Karachaganak (mostly gas), Kashagan (oil), Uzen, Korolev, Tenge, Uritau (gas), Zhanazhol
Major Oil Ports: Atyrau and Aqtau on the Caspian Sea
Oil Export Pipelines: Tengiz-Novorossiisk (Russia); Uzen-Atyrau-Samara (Russia); Kenkyak-Orsk (Russia) line that transports oil from the Aktyubinsk fields to the Orsk refinery
Major Oil Refineries (crude oil refining capacity): Pavlodar (162,666 bbl/d); Atyrau (104,427 bbl/d); Shymkent (160,000 bbl/d)
Major Power Plants (capacity): Ekibastuz No.1 (4,000 megawatts, MW), Yermak (2,400 MW), Zhambyl (1,230 MW)

Sources for this report include: AFX-Asia, Agence France Presse, BBC Monitoring Central Asia Unit, Central Asia & Caucasus Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlookm, The Economist, U.S. Deparment of Energy, U.S. Energy Information Administration, Environment News Service, The Financial Times, FSU Oil and Gas Monitor, Hart's European Fuels News, Interfax News Agency, The Moscow Times, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, U.S. Department of State, The Times of Central Asia, and Ukraine Business Report.

Links

For more information from EIA on the Kazakhstan, please see:
EIA: Country Information on Kazakhstan
EIA: Caspian Sea Region

Links to other U.S. government sites:
U.S. Agency for International Development
CIA World Factbook
U.S. Department of Commerce's Business Information Service for the Newly Independent States (BISNIS): Kazakhstan
U.S. Department of Commerce's Country Commercial Guide: Kazakhstan
U.S. Department of Commerce, International Trade Administration: Energy Division
U.S. Department of Commerce, Trade Compliance Center: Market Access Information

Library of Congress Country Study on the former Soviet Union
Radio Free Europe/Radio Liberty
RFE/RL: Energy Politics in the Caspian and Russia
U.S. State Department: Background Notes
U.S. Embassy, Almaty, Kazakhstan

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Energy Information Administration

May 2002

Central Asia

Central Asia is gaining in importance to world energy markets, due to the region's vast untapped oil and natural gas reserves. Central Asia's lack of export pipelines, in addition to Central Asia's remoteness from markets, has limited development of natural resources, but foreign investment in Central Asia, particularly in Kazakhstan, could allow the region to reach its energy-producing potential.

Note: Information contained in this report is the best available as of May 2002 and is subject to change.

GENERAL BACKGROUND
With the collapse of the U.S.S.R. in 1991, the Soviet republics of Central Asia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan, became independent for the first time in their history. The Central Asian countries, whose centrally-planned economies were heavily dependent on Soviet subsidies, were unprepared for independence, and their national economies immediately went into a tailspin. The loss of markets and disrupted trading links that accompanied the collapse of the Soviet Union had devastating effects on the Central Asian economies.

Economic and political reforms have proceeded slower in Central Asia than elsewhere in the Commonwealth of Independent States (CIS). Many political leaders in the region are former communists, and autocratic decision-making is still prevalent. Each of the Central Asian countries remains economically tied to Russia, and as a result suffered substantial losses after Russia's August 1998 financial crisis. Since then, the countries of Central Asia have become more competitive economically, and each country has experienced several years of growth. Kazakhstan and Turkmenistan, buoyed by oil and natural gas exports, respectively, have experienced the largest real gross domestic product (GDP) increases. Although Russia still controls much of the region's oil and natural gas export routes, new export options are in development, and energy exports are likely to prove a major driver behind Central Asia's future economic growth.

REGIONAL ENERGY ISSUES
Central Asia's plentiful oil and natural gas reserves have made the region an increasingly important area for world energy supply security. The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk

Road) was launched at a European Union (EU) conference in 1993, bringing together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an east-west axis, leading to increases in oil and natural gas production from Central Asia. Export pipelines, especially for natural gas, are still needed in order to facilitate further increases in Central Asia's energy production.

With the opening of its Caspian Pipeline Consortium (CPC) pipeline, Kazakhstan, for one, is beginning to export more oil to customers outside of the region. However, Central Asia's remoteness from world markets, as well as its lack of infrastructure to export its oil, natural gas, and electricity to customers outside the region, has meant that much of the Central Asia's energy is consumed internally. In addition, under the Soviet Union, much of the region was intertwined economically, and the newly independent Central Asian states in many ways remain dependent on each other, especially for energy supplies. Thus, the Central Asia states each face the dilemma of finding export outlets for their energy supplies at world market prices while also securing inexpensive energy from their neighbors for their own impoverished people.

Oil Exports

Central Asia's biggest oil producer is Kazakhstan, which produced approximately 811,000 barrels per day (bbl/d) in 2001, followed by Turkmenistan (159,000 bbl/d in 2001) and Uzbekistan (137,300 bbl/d in 2001). With its bountiful oil reserves and a relatively business-friendly investment climate, Kazakhstan has attracted substantial foreign investment to its oil sector, providing a significant boost to its oil industry. In addition to the Atyrau-Samaraand CPC export pipelines via Russia, Kazakhstan has a number of oil export options open to it. A number of Caspian Sea region oil export pipelines involving Kazakhstan are in development or under consideration.

Export options for Turkmenistan and Uzbekistan, which is doubly landlocked, are more limited. Turkmenistan has no oil pipelines, meaning that all the crude oil exported from Turkmenistan is shipped by sea. Even after shipping its oil by tanker to Russia's Caspian Sea port of Makhachkala, however, securing pipeline access has been a problem for Turkmenistan. In 2000, Turkmenistan arranged with Russian pipeline company Transneft to export up to 50,000 bbl/d via the Makhachkala link to the Baku-Novorossiisk pipeline. Since Turkmen oil has a relatively high content of sulfur and parrafins and high viscosity, Transneft determined it was not fit for the pipeline.

In order to load the oil into the pipeline, Transneft built the Dagar processing complex so that the heavy Central Asian oil could be mixed with light West Siberian oil and brought up to the Urals export standard. However, oil companies and traders supplying oil from Central Asia refused to use the complex, and Transneft refused to load it, leaving tankers with Turkmen oil standing in port. Turkmenistan eventually accepted rail transportation of its oil. Owing to reduced Kazakh and Azeri oil in the Russian pipeline system, Transneft has relented to accept increased Turkmen oil exports in the Makhachkala-Novorossiisk pipeline in order to utilize more of the pipeline's capacity. Turkmenistan is planning to export about 20,000 bbl/d via Makhachkala in 2002.

Turkmenistan increasingly has turned to swap agreements with Iran in order to export its oil, with Turkmen oil being delivered to the Iranian Caspian port of Neka. The oil swaps began in July 1998. Dragon Oil, which produced approximately 7,000 bbl/d in 2001 in a production-sharing agreement (PSA) with Turkmenistan, has exported its share of this production through a swap deal with Iran since 1998, and in April 2000 the company signed a new 10-year swap agreement with Iran. U.S.economic sanctions on Iran have prohibited American oil companies with investments in Turkmenistan from participating in the oil swaps. Also, any significant investment in an Iranian oil project by a foreign energy company may be subject to the Iran and Libya Sanctions Act, which the U.S. Congress renewed in August 2001.

Uzbekistan's only current oil export option is to reverse an existing crude oil pipeline that brings oil from Omsk, Russia, to Uzbek refineries. Uzbekistan has signed a memorandum of understanding with Turkmenistan, Afghanistan, and

Pakistan to build the Central Asia Oil Pipeline (CAOP), which, if constructed, would transport Uzbek and Turkmen oil via Afghanistan to a proposed new deepwater port at Gwadar on Pakistan's Arabian Sea coast. Continuing unrest in Afghanistan has stalled any progress on the CAOP, and the relatively small volumes of Uzbek oil that will be available for export over the next 10-20 years are insufficient to support the construction of a new export pipeline without additional volumes from other Central Asian countries.

Natural Gas Exports

The five former Soviet Central Asian countries hold nearly 4% of the world's natural gas reserves, and both Uzbekistan and Turkmenistan are already major natural gas producers. In 2000, Uzbekistan produced 1.99 trillion cubic feet (Tcf) of natural gas, followed closely by Turkmenistan, which produced 1.64 Tcf of natural gas in that same year. Although it only produced 314.3 billion cubic feet (Bcf) of natural gas in 2000, Kazakhstan has considerable proven natural gas reserves, and the country's possible reserves in its sector of the Caspian Sea could make Kazakhstan a major natural gas producer in coming years.

As Kazakhstan, Turkmenistan, and Uzbekistan continue to develop their natural gas industries and increase their production, senior Russian officials--including President Vladimir Putin--have called for a Eurasian alliance to offset the impact of European natural gas market liberalization. According to Putin, the so-called "Gas OPEC," uniting Russia with the three big natural gas-producing countries in Central Asia, would "bring an element of stability into the transportation of natural gas on a long-term basis." Analysts have criticized the alliance proposal as a Russian attempt to exercise control over Central Asian natural gas exports.

Central Asia's main natural gas export, the Central Asia-Center pipeline, already is routed into the Russian natural gas pipeline system, as is the Bukhara-Urals pipeline. In an effort to diversify export routes, a number of natural gas pipelines originating in Central Asia are under consideration. In addition to Caspian Sea natural gas export pipeline proposals, such as the Trans-Caspian Gas Pipeline, a pipeline that exports Turkmen natural gas via to Iran, the Korpezhe-Kurt Kui pipeline, has already been constructed, and a proposed Trans-Afghan pipeline is under consideration to export Central Asian natural gas via Afghanistan to Pakistan. Central Asia also has a number of internal pipelines, including the Tashkent-Bishkek-Almaty pipeline, to serve natural gas customers in the region.

Central Asia-Center Pipeline

The Central Asia-Center pipeline, built in 1974, has two branches. The western branch delivers Turkmen natural gas from near the Caspian Sea region to the north, while the eastern branch pipes natural gas from eastern Turkmenistan and southern Uzbekistan in a northwest direction across Uzbekistan. The pipeline branches meet in western Kazakhstan, where they run further directly north and enter the Russian natural gas pipeline system. Turkmenistan has been the chief exporter of natural gas via the Central Asia-Center pipeline, which has a 3.53-Tcf combined capacity.

Over 90% of Turkmenistan's natural gas exports via the pipeline go through the eastern branch, since the majority of Turkmen natural gas production is in the eastern part of the country, and also because the western branch of the pipeline is in poor technical condition. In 2001, Turkmenistan had planned to export 1.41 Tcf of natural gas via the Central Asia-Center pipeline, including 1.06 Tcf to Ukraine and another 353 Bcf to Russia. However, Turkmenistan exported only about 1.16 Tcf via this route, which Turkmen officials attributed to the limited capacity of the Kazakh segment of the pipeline.

Turkmenistan has sought to reconstruct compressor plants and pipeline sections of the western branch that are on its territory, but Turkmen President Saparmurat Niyazov has complained that sections of the pipeline that are in Uzbekistan and Kazakhstan are obsolete and require modernization. According to Turkmenistan, capacity on the Central Asia-Center pipeline is only about 2.4-2.5 Tcf presently due to a lack of maintenance and repair. Turkmenistan has stated that this is restraining its export capacity to the north, since the country could increase its natural gas production if the pipeline's capacity were increased. In 2002, Turkmenistan is planning to export 1.77 Tcf of natural gas via the Central Asia-Center pipeline, with 1.41 Tcf to be piped via Russia to Ukraine.

Trans-Caspian Gas Pipeline
As part of its strategy to increase its natural gas exports, Turkmenistan is developing alternatives to Russia's pipeline network. Among the proposals is the 1,020-mile Trans-Caspian Gas Pipeline (TCGP), which would run from Turkmenistan under the Caspian Sea to Azerbaijan, through Georgia, and then to Turkey. The pipeline's initial natural gas throughput would be 565 Bcf, eventually rising to 1.1 Tcf.

TCGP has encountered numerous problems, including competition with Azeri and Russian natural gas to supply the Turkish natural gas market. Russia's "Blue Stream" pipeline to Turkey is nearly completed, and construction on the Baku-Erzurum natural gas pipeline is scheduled to begin in 2002. Although Azerbaijan and Turkmenistan resumed talks on the TCGP in October 2001, the lack of a legal framework governing the use of the Caspian Sea continues to complicate the issue of constructing the pipeline. In addition, several of the Caspian littoral states are opposed to trans-Caspian pipelines on environmental grounds.

Korpezhe-Kurt Kui Pipeline
In December 1997, Turkmenistan launched the $190-million Korpezhe-Kurt Kui pipeline to Iran, the first natural gas export pipeline in Central Asia to bypass Russia. The 124-mile pipeline, which had an initial capacity of 141 Bcf, will have a peak capacity of 282 Bcf per year. In 2000, Turkmenistan exported 106 Bcf to Iran via the pipeline, with that figure increasing to 154 Bcf in 2001.

According to terms of the 25-year contract between the two countries, Turkmenistan will pipe between 177 Bcf and 212 Bcf of natural gas to Iran annually, with 35% of Turkmen supplies allocated as payment for Iran's contribution to building the pipeline. In December 2001, the presidents of Turkmenistan and Armenia reached an agreement by which Turkmenistan will supply up to 70.6 Bcf per year to Armenia via the Korpezhe-Kurt Kui pipeline and across Iran. Implementation of this deal is contingent on the construction of a long-delayed Iran-Armenia natural gas pipeline.

Trans-Afghan Pipeline
In October 1997, Unocal set up the Central Asian Gas Pipeline (Centgas) consortium to build a pipeline from Turkmenistan across Afghanistan to Pakistan. However, in early August 1998, Unocal announced that Centgas had not secured the financing necessary to begin the work, and on August 22, 1998, Unocal suspended construction plans for the pipeline due to the continuing civil war in Afghanistan and the U.S. missile attacks on suspected terrorist training camps.

Until recently, the pipeline was considered effectively dead, but with a fragile peace in Afghanistan established and the Taliban removed from power, the idea of a trans-Afghan pipeline has been revived. Under the original plans, the pipeline would run 900 miles from the Turkmen natural gas deposit at Dauletabad through Kandahar, Afghanistan, and terminate in yhe Pakistani city of Multan. Uzbekistan also signed a memorandum of understanding with Turkmenistan, Afghanistan, and Pakistan to participate in the Centgas pipeline project. A 460-mile stretch of the pipeline, which would have a capacity of between 706 Bcf and 1.06 Tcf, would cross Afghan territory. Approximately 12% of the pipeline's capacity would be reserved for Afghan natural gas.

Turkmen President Saparmurat Niyazov and interim Afghan leader Hamid Karzai have expressed their support for the pipeline, which would cost an estimated $2 billion. Uzbek President Islam Karimov is also on record advocating the pipeline. In March 2002, Karzai, Niyazov, and Pakistan President Pervez Musharraf agreed to hold trilateral talks on the pipeline proposal at the end of May 2002.

Tashkent-Bishkek-Almaty Pipeline

Uzbekistan's main natural gas export pipeline has been the Tashkent-Bishkek-Almaty pipeline which runs through northern Kyrgyzstan to southern Kazakhstan. The pipeline is the main source of natural gas for Kyrgyzstan and southern Kazakhstan. Irregular supplies from Uzbekistan, illegal tapping of the pipeline by Kyrgyzstan, and mounting debts by both Kazakhstan and Kyrgyzstan for supplies already received have led to increased tension between the three neighbors. Kyrgyzstan's agreement with Uzbekistan to supply it with water for the growing season, in addition to electricity, in exchange for natural gas supplies has served to complicate relations between the two states.

For its part, Uzbekistan periodically has cut off supplies to Kyrgyzstan in an effort to force Kyrgyzstan to pay its debts for natural gas supplies, which stood at approximately $1.6 million in March 2002. Kyrgyzstan has complained about the supply disruptions, which frequently occur during winter, leaving Kyrgyz consumers without adequate heat and power. Adding to the conflict, in December 2001 Kyrgyz companies illegally took 0.4 Bcf of Uzbek natural gas intended for Kazakhstan. Kyrgyz authorities explained that they had to use the natural gas following the sudden suspension of Uzbek natural gas supplies to Kyrgyzstan.

In December 2001, Kyrgyzstan agreed to turn its section of the pipeline into a concession for 10 years in payment for its debts to Kazakhstan. If Kyrgyzstan had not agreed to give its 90-mile section of the Tashkent-Bishkek-Almaty pipeline in concession, Kazakhstan had drawn up plans to start building a $70-million pipeline to bypass Kyrgyzstan. As a result of Kyrgyzstan's vulnerability to supply disruptions from Uzbekistan, the Kyrgyz government has begun importing more natural gas from Kazakhstan, as well as entered into negotiations with Kazakh and Russian officials about continuing to the construction of a natural gas pipeline from Russia to Kyrgyzstan. Completing the pipeline, whose construction was halted in 1991, would require $60 million.

Kazakh-Uzbek relations also have been strained over natural gas supplies via the Tashkent-Bishkek-Almaty pipeline. Kazakh officials have complained about Uzbekistan's irregular pricing policy. Uztransgaz, Uzbekistan's monopoly natural gas distribution company, repeatedly has attempted to increase its prices for supplies to southern Kazakhstan. According to a February 2002 agreement, Uztransgaz will supply 46 Bcf of Uzbek natural gas to southern Kazakhstan at a price of $40 per 1,000 cubic meters. Earlier, Uztransgaz proposed that Kazakhstan should pay $45 per 1,000 cubic meters. In 2001, Kazakhstan announced its intention to develop the Amangeldy natural gas field in its southern regions in order to end the country's reliance on Uzbek imports.

Other Central Asian Natural Gas Pipelines

Natural gas pipelines also run from Uzbekistan to Tajikistan's capital of Dushanbe, as well as through northern Tajikistan. Tajik and Uzbek officials have been operating under an arrangement where Uzbekistan supplies Tajikistan with natural gas as payment for Uzbekistan's use of a transit pipeline which crosses the Leninabad region of northern Tajikistan and links Uzbekistan's eastern territory with its natural gas fields. Tajikistan has contracted with Uzbekistan for additional natural gas, owing to overconsumption by Tajik consumers, and Tajikgaz, Tajikistan's state natural gas distribution company, has run up a $2 million debt to Uzbekistan for supplies already received.

With the volume of Turkmen natural gas transiting Kazakhstan on the rise, the Bukhara-Urals pipeline has been pressed into service. In March 2001, natural gas transit started on the previously inactive pipeline, with approximately 200 Bcf exported via the pipeline in 2001. KazTransGaz, Kazakhstan's natural gas transportation company, invested about $20 million in modernizing its section of the Bukhara-Urals pipeline system in 2000.

Electricity Exports

Several countries in the Central Asia region have electricity available for export, and there is also substantial untapped hydropower potential in both Kyrgyzstan and Tajikistan. In the Fergana Valley, eastern Uzbekistan, northern Tajikistan, and southern Kyrgyzstan are intertwined geographically, and because their power grids are interconnected, they are able to export power to each other as needed.

In general, Kyrgyzstan and Tajikistan export their seasonal hydropower to Uzbekistan in the summer, when both generate excess electricity, and Uzbekistan supplies Tajikistan and Kyrgyzstan with electricity in winter months. In 2001, Uzbekistan supplied 0.2 billion kilowatt-hours (Bkwh) of electricity to Tajikistan in the winter period, and received 0.3 Bkwh from Tajikistan in the summer. In October 2001, Kyrgyzstan agreed to accept 0.5 Bkwh of electricity in Uzbekistan in exchange for guaranteeing the accumulation of water in its Toktogul water reservoir so that irrigation water will last for Uzbekistan through the growing season in 2002.

Tajikistan, Uzbekistan, and Turkmenistan also have started electricity exports to Afghanistan. In mid-March 2002, Tajikistan began experimental exports to Afghanistan's northern provinces, and in that same month Uzbekistan resumed electricity shipments to Afghanistan, three years after halting deliveries. Under an intergovernmental agreement signed on March 7, 2002, Turkmenistan is set to spend $520 million on projects to export Turkmen electricity to Afghanistan. In the first stage, Turkmenistan will build and overhaul power lines, including the 50-megawatt (MW) Mary-Shibirgan-Mazar-e-Sharif line. In the second stage, the power line will be extended to Kabul and power capacity will increase to 200 MW. A Mary-Serkhetabat-Herat-Kandahar power line also will be built with a 200-MW capacity.

Table 1. Economic and Demographic Indicators for Central Asia

Country	Gross Domestic Product (Nominal GDP), 2001E (Billions of U.S. $)	Real GDP Growth Rate, 2001 Estimate	Real GDP Growth Rate, 2002 Projection	Per Capita GDP, 2001E	Population 2001E (Millions)
Kazakhstan	$21.4	13.2%	7.0%	$1,442	14.8
Kyrgyzstan	$1.5	6.6%	5.3%	$290	5.0
Tajikistan	$1.0	9.5%	7.5%	$152	6.3
Turkmenistan	$5.4	18.0%	13.0%	$988	5.5
Uzbekistan	$10.8	4.3%	4.4%	$428	25.3
Total/weighted average	$40.1	11.1%	7.1%	$705	56.9

Source: DRI/WEFA

Table 2. Energy Consumption and Carbon Dioxide Emissions in Central Asia, 1999

Country	Total Energy Consumption (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Electricity	Net Electricity Imports	Carbon Dioxide Emissions (Million metric tons of carbon)
Kazakhstan	1.46	29.5%	34.5%	29.9%	0.1%	4.0%	0%	2.1%	26.6

Kyrgyzstan	0.22	12.9%	31.1%	8.4%	0%	56.1%	0%	-8.5%	2.0
Tajikistan	0.26	21.6%	16.0%	0.9%	0%	60.7%	0%	0.8%	1.8
Turkmenistan	0.30	41.5%	68.9%	0%	0%	0.02%	0%	-10.4%	5.4
Uzbekistan	1.88	15.7%	76.8%	2.3%	0%	3.2%	0%	2.0%	27.7
Total/ weighted average	4.12	22.7%	55.0%	12.2%	0.04%	9.7%	0%	0.5%	63.5

Source: Energy Information Administration
Note: percentages may not add up to 100% due to rounding.

Table 3. Energy Supply Indicators, Central Asia

Country	**Proven Crude Oil Reserves, 1/1/02E (Million Barrels)**	**Natural Gas Reserves, 1/1/02E (Trillion Cubic Feet)**	**Coal Reserves, 1/1/01E (Million Short Tons)**	**Petroleum Production, 2001E (Thousand Barrels Per Day)**	**Natural Gas Production, 2000 (Billion Cubic Feet)**	**Coal Production, 2000 (Million Short Tons)**	**Electric Generating Capacity, 2000 (Gigawatts)**	**Crude Oil Refining Capacity, 1/1/02E (Thousand Barrels Per Day)**
Kazakhstan	5,417	65	37,479	811	314.3	82.4	17.3	427
Kyrgyzstan	40	0.2	895	2.1	0.5	0.8	3.8	10
Tajikistan	12	0.2	minimal	0.4	1.4	0.02	4.4	0.4
Turkmenistan	546	101	minimal	159	1,642	0	3.9	237
Uzbekistan	594	66.2	minimal	137	1,992	3.3	11.7	222
Total	6,609	232.6	38,374	1,109.5	3,950.2	86.52	41.1	896.4

Source: Energy Information Administration

Sources for this report include: AFX-Asia, Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring Central Asia Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, The Economist, The Financial Times, FSU Oil and Gas Monitor, Interfax News Agency, The International Herald Tribune, ITAR-TASS News Agency, The Moscow Times, Petroleum Economist, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, and World Markets Online.

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April 2002

Russia

Russia is important to world energy markets because it holds the world's largest natural gas reserves, the second largest coal reserves, and the eighth largest oil reserves. Russia is also the world's largest exporter of natural gas, one of the largest oil exporters, and the third largest energy consumer.

Note: Information contained in this report is the best available as of April 2002 and is subject to change.

GENERAL BACKGROUND

After a banner year in 2000, when Russia's real gross domestic product (GDP) grew by 8.3%, Russia's economic growth slowed in 2001. Nevertheless, Russia's economy grew by a healthy 5.1%, and the country's economy is in the best shape it has been in since the breakup of the Soviet Union in 1991. Russia's rate of inflation slowed from 20.2% in 2000 to 18.5% in 2001, and Russia's currency, the ruble, continued to strengthen in 2001, prolonging its remarkable rebound from the country's August 1998 financial crisis and devaluation.

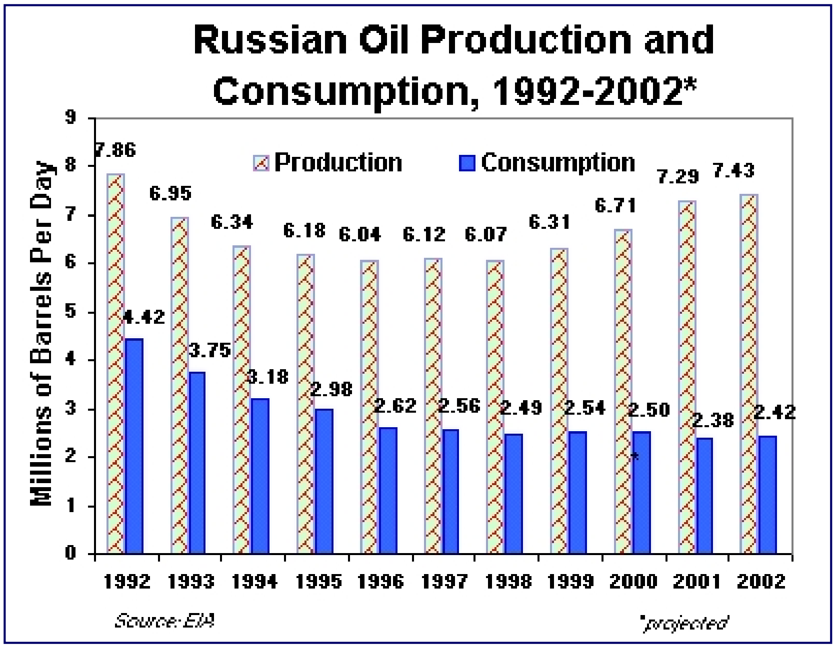
Since energy accounts for approximately 40% of Russia's exports and 13% of the country's real GDP, Russia's economy is extremely sensitive to global energy price fluctuations. As a result, the decline in world oil prices in 2001 put the brakes on Russia's economic recovery, which was fueled by high world oil prices in 1999-2000 and the increased competitiveness of Russian exports in the aftermath of the 1998 financial crisis. Although the windfall in oil export revenues in 1999-2000 stimulated increases in other industrial sectors and helped the Russian government pay down some of its $154 billion foreign debt, structural reforms slowed in the euphoria of the oil revenues.

The drop in world oil prices after September 11, 2001, resulted in members of the Organization of Petroleum Exporting Countries (OPEC) requesting Russia and other non-OPEC members to cut their oil exports in order to boost prices. Russia agreed with OPEC in December 2001 to cut its oil exports by 150,000 bbl/d during the first quarter of 2002. Despite heavy lobbying by Russian oil companies to end the cut and to increase exports, Russia, whose state budget for 2002 is based on an average oil price of $23 per barrel and a minimum price of $18 per barrel, decided in March 2002 to continue its self-imposed cuts by 150,000 bbl/d through June 2002.

Although reforms have been slow in coming, restructuring and liberalizing the energy sector and making the Russian economy less dependent on oil and natural gas exports is a stated priority for Russian President

Vladimir Putin and the Russian government. Plans to break up the monopoly positions of both Gazprom and Unified Energy Systems, the Russian natural gas and electricity monopolies, have been approved. Similarly, the Russian government has pledged to improve the investment climate in Russia, but Russia's unstable tax and legal codes have kept many foreign energy companies from investing in Russia's energy sector. Russia has plans for a number of new oil and natural gas pipelines, and massive infrastructure investments will be needed to develop several planned international oil and gas projects.

OIL



After several years of production declines following the collapse of the Soviet Union, Russia's oil industry has bounced back over the past few years, posting strong profits and healthy increases in production. Russia is one of the world's biggest oil producers, but from 1992 to 1998, the country's oil production plummeted 23% due to decreased domestic industrial demand and a decline in drilling and capital investment.

Buoyed by high world oil prices in 1999-2000, Russian oil companies reinvested much of their generous profits into ramping up crude production. Since 1998, when production bottomed out at 6.07 million bbl/d, Russia's oil production, including condensates, has increased 20%, with overall production of 7.29 million bbl/d in 2001.

Despite Russia's pledge to OPEC to shave 150,000 bbl/d off its oil exports in the first half of 2002, Russian oil production is still forecast to post a 1.9% year-on-year increase--reaching 7.43 million bbl/d--in 2002. Russian oil production actually increased in the first few months of 2002, with average oil production of 7.49 million bbl/d in February 2002. Although Russian government officials have attempted to limit the country's oil exports, new export channels, such as the Baltic Pipeline System, have provided a powerful disincentive to Russian oil producers to reduce their output. As a result of Saudi Arabia's OPEC-mandated production cut (and that country's better compliance with its pledged cuts), Russia's oil production surpassed Saudi Arabia's in February 2002 for the first time since the Soviet era, making Russia the world's leading oil producer, if only temporarily.

Russia has proven oil reserves of 48.6 billion barrels, but aging equipment and poorly developed fields are making it difficult to develop these reserves. In addition, Russia's rate of oil production is exceeding its rate of discovery of new reserves by a significant margin. The Russian oil industry faces the depletion of existing oilfields, deterioration in transport infrastructure, and an acute shortage of investment due to the confusing tax and legal environment. In order to sustain and to increase Russia's oil production from current levels, large amounts of capital will be needed to develop new fields and to extend the life of existing oilfields with exhausted and low-yield reserves.

However, the sharp rise in oil prices during 1999-2000 provided Russian oil companies with a windfall in revenues, and many have begun to upgrade decaying oil infrastructure and to undertake new exploratory drilling. In addition to further development of the West Siberia region, where most of Russia's oil comes from currently, Russian oil producers are conducting more exploration in the Russian sector of the Caspian Sea, and teaming up with foreign oil producers to develop oil projects in the Arctic region, Eastern Siberia, and Sakhalin Island in Russia's Far East. Russia's future level of oil production will be defined by the ability of oil companies to develop these new deposits, which will require a massive amount of infrastructure investment (including new export pipelines) in order to deliver this oil to customers.

Oil Sector Reform

Russia reorganized its state-run oil industry into a number of vertically-integrated oil companies in the early 1990s, and the state has divested itself of large stakes in most of these companies. Nonetheless, foreign investment in the industry has been minimal due to economic and political instability, a poor record of corporate governance, and the unstable legislative framework.

In order to create a more stable investment climate, potential investors have called upon the Russian government to undertake further reform, including the establishment of cohesive production-sharing agreement (PSA) framework legislation. Although the political and economic situation has stabilized since the August 1998 financial crisis, and high world oil prices in 1999-2000 enticed some investors into Russia, others are still awaiting the passage of a new Russian PSA regime and tax code.

Oil Exports

Despite problems surrounding the transition to a market economy and the lack of foreign investment in its oil sector, Russia remains one of the world's top oil exporters. After Russian oil exports slumped in the mid-1990s, exports rebounded after the ruble devaluation of August 1998 reduced production costs sharply for Russian oil producers, and the climb in world oil prices in 1999-2000 made exports even more profitable for Russian oil companies. With domestic consumption of 2.38 million bbl/d in 2001, Russia's increased its net oil exports in 2001 to 4.91 million bbl/d, making Russia the world's second largest oil exporter, behind only Saudi Arabia.

Russia is not a member of OPEC, but in recent years it has frequently attempted to coordinate its export strategy with OPEC. Although Russia agreed to reduce its oil exports by 150,000 bbl/d in the first quarter of 2002, Russian oil companies' compliance with these export cuts has been questionable at best, with preliminary data showing that Russian crude oil exports actually increased during the first quarter of 2002. Russian government officials levied higher export tariffs and set crude oil export quotas in order to limit the country's oil exports, but Russian oil companies increased their oil product exports instead. For 2002 as a whole, Russia's net oil exports are projected to increase to 5.01 million bb/d.

Oil Pipelines

Russia's oil exports could be even higher if they were not restricted by a lack of spare capacity in existing export pipelines. Despite Russia's pledged export cuts, the country's main export pipeline, the 1.2-million-bbl/d-capacity Druzhba pipeline, still is operating close to its highest capacity in years. In addition, many of the country's oil pipelines are in a state of disrepair, and Russian Energy Ministry figures indicate that almost 5% of crude oil produced in Russia is lost through illegal tapping of Russia's pipelines.

With a windfall in oil export tariffs in the past several years, Transneft, the state oil transport monopoly, has taken steps to upgrade the country's pipeline system, with an emphasis on building new export pipelines to increase and diversify export routes for oil exporters. In addition to constructing the Baltic Pipeline System and a possible pipeline to China, Transneft is seeking to lure additional transit oil from Azerbaijan, Kazakhstan, and Turkmenistan.

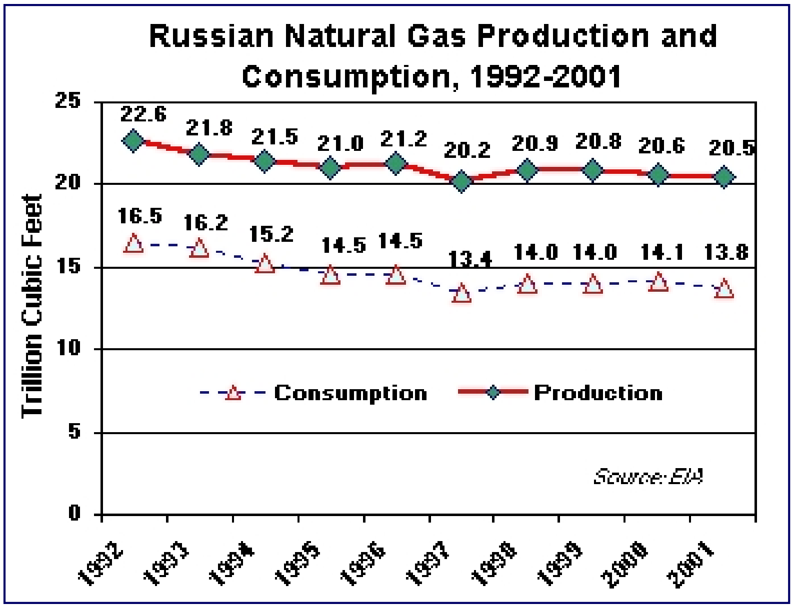
Downstream/Refining

Russia has 42 oil refineries--many of which are inefficient, aging, and in need of modernization--with a total processing capacity of 6.9 million bbl/d. With Russian domestic demand of 2.38 million bbl/d in 2001, refining capacity far outstrips demand for refined products. In addition, because a barrel of crude oil on the Russian market typically sells for just over half the world crude oil price, many Russian oil companies prefer to export their crude oil rather than to refine it in Russia. When Russian oil producers do not export their crude oil--often because of the constraints of Russia's pipeline system or the government's limits on each company's exports--many choose to supply their own refineries rather than sell the oil on the open market.

Russia's decision to go along with OPEC oil supply cuts in the winter of 2001-2002 has led to a glut of oil on the Russian market. As a result, Russian oil companies have channeled more oil into domestic refineries, and with refineries awash in crude, the domestic crude price collapsed, falling from about $13.70 per barrel at the wellhead in November 2001 to just $4.48 per barrel in January 2002. With many Russian refineries undergoing renovations or efficiency upgrades, Russia's refineries have not been able to handle so much crude oil at once. Preliminary data indicates that Russia's exports of refined products increased in the first quarter of 2002, and surplus refined products such as fuel oil, gasoline, and kerosene went into storage.

NATURAL GAS

Russia contains over 1,700 trillion cubic feet (Tcf) in proven reserves of natural gas, the world's largest. Gazprom, the state-run natural gas monopoly, produces nearly 94% of Russia's natural gas, operates the country's 90,000-mile natural gas pipeline grid and 43 compressor stations, and holds nearly one-third of the world's natural gas reserves while employing approximately 38,000 people. Often referred to as a "state within a state," Gazprom also is Russia's largest earner of hard currency, and the company's tax payments account for around 25% of federal government tax revenues.



Russia's natural gas production also is the largest in the world. Natural gas also accounts for over 54% of Russia's energy consumption, but the country still has plenty of natural gas available for export. According to Russia's State Statistics Committee, in 2001 Russia consumed 13.8 Tcf of natural gas while it produced 20.5 Tcf. With 6.7 Tcf in net natural gas exports, Russia is the world's largest natural gas exporter. In 2002, Russia is planning to increase natural gas production to 21.2 Tcf, while the country projects domestic natural gas consumption to increase to 14.6 Tcf.

In addition to its main producing areas in the Yamal-Nenets region of northern West Siberia at the Urengoy and Yamburg fields, Gazprom is responsible for future development of giant Bovanenkovskoye field on the Yamal Peninsula and other fields in the Yamal-Nenets region, including the the giant Pestsovoye and Zapolyarnoye fields to the north in the Ob-Taz Gulf area. Through its subsidiary Rosshelf, Gazprom also is responsible for development of the Shtokmanskoye field in the Barents Sea and other fields in the North Caucasus, Precaspian, Timan-Pechora, and the Volga-Urals.

Many analysts doubt Russia's ability to raise its natural gas production in the face of Gazprom's declining budget and the low levels of investment to the sector in recent years. Although Russia's natural gas sector has not been as hard hit as other sectors of the energy industry during the transition to a market economy (production is down just 9% since 1992), low investment in the sector has raised concerns about future production levels. Production in the Urengoy and Yamburg natural gas fields is declining, while the planned development of new fields continues to be delayed as a result of lack of investment resources. In February 2002, Gazprom scaled back its 2002 investment program for field exploration to $453 million from the $499 million invested in 2001.

Sectoral Problems

According to the Russian Gas Law of 1999, Gazprom must supply the Russian natural gas market, regardless of profitability, at regulated prices. Thus, the company is forced by the Russian government to sell natural gas to domestic users for approximately $16 per 1,000 cubic meters (35,300 cubic feet)--less than it costs the company to produce, and only about one-tenth of the export price of $140-$150 per 1,000 cubic meters.

In addition, Gazprom continues to be hurt by chronic non-payments by consumers (although this situation has improved recently). In 1999, Russian consumers paid only 39% of their bills for natural gas in cash, but by 2001, Gazprom was paid in cash for 83% of the natural gas it sold domestically. Still, only 29 of Russia's 89 regions are up to date with their natural gas payments, and the multi-billion dollar debt of domestic natural gas consumers has hindered Gazprom's ability to invest adequately in new fields, many of which need major infrastructure investments.

The only investment in new natural gas production that Gazprom has made recently is the development of Zapolyarnoye, which was brought onstream in October 2001 to offset the decline in the company's production. Although Gazprom has enough undeveloped natural gas reserves in its portfolio to ensure future supplies, Zapolyarnoye is the last of the so-called "easy-to-develop" giant fields. Development of future fields, most of which are located in the more remote regions that lack infrastructure to deliver the natural gas to consumers, will require much higher levels of investment. Developments like Prirazlomnoye and Shtokmanskoye are provisionally budgeted to cost $1 billion and $15 billion to $20 billion, respectively.

Restructuring the Natural Gas Sector

While Gazprom is looking to establish partnerships with foreign investors to develop several natural gas production projects, restrictions on foreign investment in the company, along with allegations of asset stripping by senior managers of Gazprom, has limited Russia's investments in new natural gas developments. In addition, Gazprom's control over Russia's natural gas trunk-line system, forcing other producers to sell their natural gas to Gazprom on its terms, has proven a disincentive to increased natural gas production. The lack of access to Russia's natural gas pipelines has meant that Russian oil companies prefer to flare their associated natural gas instead of treating it and selling it to Gazprom.

In an attempt to spur increased investment in the industry and to raise production levels, President Putin is taking steps to end Gazprom's monopoly position and to restructure the natural gas sector. On November 9, 2000, the government ordered Gazprom to give other companies the right to use up to 15% of its pipeline capacity, and in May 2001, Gazprom's Board of Directors ousted long-time chief Rem Vyakhirev and replaced him with Aleksei Miller, an ally of Putin.

A restructuring plan currently under consideration would break Gazprom's upstream operations into separate producing companies in order to foster competition on the Russian domestic market, while the government would take control of Gazprom's transmission pipelines, offering equal access to all natural gas producers, thereby giving incentive to Russia's oil companies to treat the associated natural gas they develop. In addition, the Russian government is paying heed to Gazprom's minority shareholders, curtailing Gazprom's mysterious relationship with natural gas trader Itera and attempting to loosen restrictions on the purchasing of Gazprom shares by foreign investors.

Natural Gas Exports

The Russian government's determination to keep domestic natural gas prices artificially low means that the country's natural gas industry is heavily dependent on exports to finance its production. In 2001, Russia totaled 6.7 Tcf of net natural gas exports, the majority of which were piped to customers outside the Commonwealth of Independent States (CIS). Gazprom supplies Europe with 25% of its natural gas, and with several new export pipelines planned or already under construction, Russia hopes to increase this percentage in the next decade.

In order to offset its own declining production and maintain its export level, Gazprom, via natural gas trader Itera, contracted to buy 353 billion cubic feet (Bcf) of gas from Turkmenistan in 2002. As

Kazakhstan, Turkmenistan, and Uzbekistan continue to develop their natural gas industries and increase their production, senior Russian officials--including President Putin--have called for a Eurasian alliance to offset the impact of European natural gas market liberalization. According to Putin, the so-called "Gas OPEC," uniting Russia with the three big natural gas-producing countries in Central Asia, would "bring an element of stability into the transportation of natural gas on a long-term basis." Analysts have criticized the alliance proposal as a Russian attempt to exercise control over Central Asian natural gas exports.

Natural Gas Export Pipelines

In an effort to diversify its export routes and reach new markets, Russia is planning to build several new natural gas export pipelines. The Blue Stream pipeline to Turkey is the centerpiece of Russia's export diversification strategy. The pipeline, which will supply Turkey with 565 Bcf of natural gas via twin pipelines laid on the bottom of the Black Sea, is nearing completion, and should be operational by the fall of 2002. The December 2001 resolution of the dispute between Russia and Ukraine over Ukraine's unsanctioned removal of natural gas has caused Gazprom to drop plans to build a "Ukraine bypass" pipeline, but plans for the second branch of the Yamal-Europe pipeline--to Europe via Belarus--are in development. In addition, Russia is looking eastwards, with several potential natural gas pipelines to China currently under consideration.

COAL

With 173 billion short tons in proven coal reserves, Russia holds the world's second largest coal reserves, behind only the United States. However, years of poor management during the Soviet era, combined with a sharp decline in demand for coal during the early 1990s, significantly undermined the Russian coal sector's viability in the early 1990s. By 1993, Russian government subsidies to the coal sector became unsustainably high, exceeding 1% of the country's GDP, according to the World Bank. As production began to slump, Russia initiated a comprehensive restructuring of the coal sector in the mid-1990s.

As a result of the restructuring, the state coal company, RosUgol, has been phased out, production subsidies have ended, and mines with no economic future are being closed. With over $1.3 billion in financial assistance provided by the World Bank, the restructuring efforts are paying off, and the transition of Russia's coal sector from a massively-subsidized industry into a streamlined, profitable operation is almost complete. After years of decline, which saw Russian coal production decrease by 41%--from 406 million short tons (Mmst) in 1992 to 241 Mmst in 1998--in 1999, the reformed coal sector increased its production to 259 Mmst. EIA preliminary data for 2000 shows that Russia's coal production increased to 281 Mmst, and Russia's State Statistics Committee reports that the country's coal production rose again in 2001. Russia's Ministry of Energy has projected a 0.3% coal production increase in 2002.

Many of Russia's major coal basins are in West Siberia, and in 2001, the region's coal mines accounted for 48% of Russia's overall coal production. Kuzbassrazrezugol and Krasnoyarskugol, both located in West Siberia, were Russia's largest coal producers in 2001, with output of 36.3 Mmst and 35.3 Mmst, respectively. In addition, through the first seven months of 2001, Russia's State Statistics Committee reported that Russia's coal exports increased during the same time period by 30% year-on-year, including a 41.5% increase in exports to countries outside the CIS and Baltics.

With Russia's determination to increase its oil and natural gas exports, Russia's coal consumption is slated to rise. Although coal accounted for just 16% of Russia's domestic energy consumption in 1999, the government is committed to increase that percentage to as high as 28%. Russia consumed 298 Mmst of coal in 2000, but the country's energy strategy calls for coal production to climb to 335 Mmst in 2010, and then to 430 Mmst in 2020.

Nevertheless, the Russian Trade Union of Coal Miners complained in March 2002 of a lack of demand for Russian coal. Despite the sector's increased productivity, the Union's chairman, Ivan Mokhnachuk, said that coal deliveries to power-generation facilities fell by 4.4 Mmst in 2001, while coal stocks in depots increased by 33% over the previous year. At the same time, he noted, Russia imported 28.4 Mmst of coal from Kazakhstan. The Russian Trade Union of Coal Miners has accused both Kazakhstan and China of dumping coal on the Russian market, reducing demand for Russian-produced coal.

ELECTRICITY

Russia's mammoth power sector, which includes over 440 thermal and hydropower plants, plus 29 nuclear reactors, has a total electric generation capacity of 203 gigawatts (GW). With 139 GW of production capacity, thermal power (oil-, gas-, and coal-fired plants) accounts for 68% of the country's power generation capacity, while hydropower plants account for an additional 44 GW (21.5% of total installed power capacity). Russia's electricity sector is dominated by Unified Energy Systems (UES), which is 52%-owned by the Russian government. UES, headed by former privatization minister Anatoly Chubais, controls approximately 70% of the country's distribution system and oversees Russia's 72 regional electricity companies, called *energos*.

Russia shut down several nuclear reactors during the 1990s, leading to a drop in the country's power-generating capacity during the last decade from 213 GW in 1992. Nonetheless, Russia still has sufficient power production potential to supply domestic consumers, as well as export power to other countries. In 1999, Russia's total electricity generation broke a decade-long downward trend by inching up from 788 billion kilowatt-hours (Bkwh) produced in 1998 to 801 Bkwh, followed by a jump to 836 Bkwh of electricity produced in 2000.

Similarly, the economic recovery after the August 1998 financial crisis resulted in an increase in the country's total electricity consumption, from 715 Bkwh in 1998 to 767 Bkwh in 2000. Increased industrial demand for electricity also has forced power stations to operate at higher capacity, straining power companies' ability to procure fuel supplies at a time when Gazprom is continuing to reduce natural gas supplies to UES. A lack of fuel supplies at power stations has already led to periodic power outages.

Electricity Sector Restructuring

Russia's aging power sector is in serious need of investment and reform. Much of the sector is obsolete by Western standards, and Russia lacks the money to pay for necessary maintenance. UES estimates that between $20 billion and $35 billion in investment will be needed over the next 10 years for maintenance and modernization efforts, but the company currently only has about $1 billion per year to invest. Analysts have estimated that if rates of investment stay at present levels, 32% of the current stock of electricity generating equipment will be out of commission by 2005, prompting a crisis in electricity production that may lead to widespread regional power shortages.

In an effort to entice foreign electricity companies to invest in Russia's power sector, numerous reform plans have been debated over the past decade, to no avail. However, the severe power outages in Russia's Far East during the winter of 2000-2001 made power sector restructuring a high priority, and in May 2001, the Russian government approved a blueprint for electricity sector restructuring. The restructuring plan will break the UES monopoly into separate generation and distribution units, then split up the generation assets further. Russian government officials hope this will pave the way for privatization of independent power-generating companies and thereby attract much needed investment to the sector.

Electricity Exports

UES has begun to focus on electricity exports in order to increase its cash flow to allow it to procure fuel supplies, as well as to invest in maintenance and modernization projects. In October 2000, UES began to supply electricity to Europe as part of an international project to create an "East-West energy bridge." UES is participating in the Baltrel program to create an energy ring with power companies in the Baltic states, and it has also signed contracts to export power to Turkey via Georgia. In addition, in August 2001 the Ukrainian and Russian electricity grids were re-connected, allowing Russia to export electricity via Ukraine to Moldova, as well as to access the Romanian, Bulgarian, and Balkan markets.

In March 2002, during a joint meeting of the CIS Electric Power Council and the Union of the Electric Industry (Eurelectric) in Warsaw, UES Chairman Anatoly Chubais appealed to European colleagues to "destroy the iron curtain" between the energy systems of the East and the West. The first steps towards synchronization of energy systems have already been taken, as the Union for the Coordination of Transmission of Electricity (UCTE), of which 20 European countries are members, has entered into discussions with its eastern colleagues over the technological and operational aspects of amalgamating their systems.

Nuclear

With the opening of the 1,000-megawatt (MW) Rostov-1 reactor in March 2001, Russia now operates 30 nuclear reactors at 10 locations, all west of the Ural Mountains. The country has a total installed nuclear capacity of 22 GW, and in 1999 Russia's nuclear plants generated 111 Bkwh of power, accounting for 14% of the country's total electricity generation. However, Russia's nuclear power plants are aging, and the nuclear power industry has been hard hit by Russia's transition to a market economy. Russia already has shut down four reactors that were over 30 years old (the maximum prescribed service life for a reactor), but 15 of the country's 29 operating units are over 20 years old, and by 2005, seven of those reactors will have been in service for 30 years.

With Russia's plans to export additional natural gas to the West, the country's energy strategy is to increase its use of nuclear power over the next 20 years to meet domestic electricity needs. In order to do so, additional capacity will be needed, but the nuclear industry's lack of money has forced Minatom, the government agency responsible for overseeing the country's nuclear power plants, to focus on extending the service life of existing units instead of building new ones. Safety issues are an ongoing concern, especially with regard to the 16 relatively old reactors of the RBMK design used at Chernobyl. Older RBMK units at Kursk and St. Petersburg are scheduled to be overhauled and equipped with stopgap safety improvements to prolong their lives for another three decades.

Minatom is hoping to complete construction on five nuclear reactors that have been under construction since the 1980s, as well as to build 25 new reactors during the next 20 years. In February 2001, Russia's Deputy Minister of Atomic Energy, Bulat Nigmatulin, said the ministry would finance most of the $1.5 billion necessary to complete the construction of the five reactors by 2005. Although the Rostov-1 reactor is now operational, both the 1,000-MW Kalinin-3 reactor and the 1,000-MW Kursk-5 reactor are still under construction. In addition, Western nuclear experts have expressed serious doubts that Russia can finance the construction of 25 additional reactors on its own.

To increase its ability to finance domestic nuclear projects, in October 2000 Russia announced plans to market nuclear power plants to countries in Asia and Africa. The first of such plants, a $1.2-billion project for two 1,000-MW reactors, was sold to India, to be installed near Chennai by 2008. Russia also negotiated a similar deal with Iran to build the Bushehr nuclear power plant, and in November 2001, Russia delivered the first reactor body to Iran. According to the International Atomic Energy Agency, Russian-designed reactors would not be licensable in Western countries because they do not have all of the mandatory safety features, such as a containment dome.

ENVIRONMENT

After years of neglect under the Soviet Union, the environment has become a pertinent issue in today's Russia. Soviet policies that encouraged rapid industrialization and development left a legacy of air pollution and nuclear waste with which Russia now is struggling to contend. Although environmental awareness in Russia is rising, the cost of remediating the country's environmental hot spots is high, and the newly created Ministry of Natural Resources has a limited budget. As a result, cleanup has been slow, and environmental protection has not been a top priority for the Russian government.

The economic contraction in the aftermath of the Soviet Union's collapse caused a drop in industrial production, resulting in less energy consumption and a drop in Russia's carbon emissions. However, energy and carbon intensities in Russia remain high, and although per capita carbon emissions have fallen over the past 12 years, Russia will need to pursue more sustainable environmental policies in order to maintain this trend, especially with the rebound in industrial production since the August 1998 financial crisis. Russia has abundant fossil fuel resources, but the country will need to pursue more renewable energy options and cleaner environmental technologies in order to preserve its natural wonders and protect its environment for future generations.

COUNTRY OVERVIEW

President: Vladimir Vladimirovich Putin (acting president since December 31, 1999; president since May 7, 2000)
Prime Minister: Mikhail Mikhaylovich Kasyanov (since May 7, 2000)
Independence: August 24, 1991 (from Soviet Union). National holiday: Independence Day, June 12, 1990
Population (7/01E): 145.5 million
Location: Eurasia
Size: 6,592,850 sq. mi., slightly more than 1.8 times the size of the United States
Major Cities: Moscow, St. Petersburg, Yekaterinburg, Irkutsk, Murmansk, Yakutsk, Vladivostok
Languages: Russian, others
Ethnic Groups: Russian 81.5%, Tatar 3.8%, Ukrainian 3%, Chuvash 1.2%, Bashkir 0.9%, Belorussian 0.8%, Moldovan 0.7%, other 8.1%
Religions: Russian Orthodox, Muslim, other

ECONOMIC OVERVIEW

Minister of Economic Development and Trade: German Oskarovich Gref
Minister of Finance: Aleksey Leonidovich Kudrin
Currency: Ruble
Market Exchange Rate (4/25/02): $1 = 31.19 rubles
Nominal Gross Domestic Product (GDP) (2001E): $301.5 billion; **(2002E):** $327 billion
Real GDP Growth Rate (2001E): 5.1%; **(2002E):** 3.2%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 18.5%; **(2002E):** 12.8%
Official Unemployment Rate (2001E): 8.8%; **(2002E):** 8.6%
Current Account Balance (2001E): $34.3 billion; **(2002E):** $27.1 billion
Major Trading Partners (1999): Germany, Ukraine, U.S., Belarus, Italy, Netherlands, Kazakhstan
Merchandise Exports (2001E): $102.7 billion; **(2002E):** $103.7 billion
Merchandise Imports (2001E): $53.1 billion; **(2002E):** $60.0 billion
Merchandise Trade Balance (2001E): $49.6 billion; **(2002E):** $43.7 billion
Major Exports: Petroleum and petroleum products, natural gas, wood and wood products, metals, chemicals, and a wide variety of civilian and military manufactures
Major Imports: Machinery and equipment, consumer goods, medicines, meat, grain, sugar, semifinished metal products
External Debt (2001E): $154 billion

ENERGY OVERVIEW

Deputy Prime Minister (for Energy Issues): Viktor Borisovich Khristenko
Minister of Energy: Igor Khanukovich Yusufov
Minster of Atomic Energy: Aleksandr Yuryevich Rumyantsev
Proven Oil Reserves (1/1/02E): 48.6 billion barrels
Oil Production (2001E): 7.29 million bb/d (of which 7.05 million bbl/d was crude); **(2002E):** 7.43 million bbl/d
Oil Consumption (2001E): 2.38 million bbl/d; **(2002E):** 2.42 million bbl/d
Net Oil Exports (2001E): 4.91 million bbl/d; (**2002E):** 5.01 million bbl/d
Major Oil Customers: Europe, Commonwealth of Independent States
Crude Refining Capacity (1/1/02E): 6.6 million bbl/d
Proven Natural Gas Reserves (1/1/02E): 1,700 trillion cubic feet (Tcf)
Natural Gas Production (2001E): 20.5 Tcf
Natural Gas Consumption (2001E): 13.8 Tcf
Net Natural Gas Exports (2001E): 6.7 Tcf
Coal Reserves (1/1/01E): 173 billion short tons
Coal Production (2000E): 281 million short tons (Mmst)

Coal Consumption (2000E): 298 Mmst
Electric Installed Capacity (2000E): 203 gigawatts (68% thermal, 21.5% hydro, 10.5% nuclear)
Electricity Generation (2000E): 836 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 767 Bkwh
Net Electricity Exports (2000E): 69 Bkwh

ENVIRONMENTAL OVERVIEW
Minister of Natural Resources: Vitaliy Grigoryevich Artyukhov
Total Energy Consumption (1999E): 26.0 quadrillion Btu* (6.8%) of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 400.1 million metric tons of carbon (6.5% of world carbon emissions)
Per Capita Energy Consumption (1999E): 176.7 million Btu (vs. U.S. value of 355.9 million Btu)
Per Capita Carbon Emissions (1999E): 2.7 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (1999E): 72,133 Btu/$1990 (vs U.S. value of 12,638 Btu/$1990)**
Carbon Intensity (1999E): 1.1 metric tons of carbon/thousand $1990 (vs U.S. value of 0.20 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1997E): Industrial (64.3%), Residential (17.9%), Transportation (17.1%), Commercial (0.7%)
Sectoral Share of Carbon Emissions (1997E): Industrial (64.8%), Transportation (17.8%), Residential (17.4%)
Fuel Share of Energy Consumption (1999E): Natural Gas (54.3%), Oil (19.3%), Coal (16.0%)
Fuel Share of Carbon Emissions (1998E): Natural Gas (50.8%), Coal (26.2%), Oil (22.9%)
Renewable Energy Consumption (1997E): 2,482 trillion Btu* (1% increase from 1996)
Number of People per Motor Vehicle (1997): 6.5 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified December 28th, 1994). Under the negotiated Kyoto Protocol (signed on March 11th, 1999, but not yet ratified), Russia has agreed to stabilize greenhouse gases at 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: air pollution from heavy industry, emissions of coal-fired electric plants, and transportation in major cities; industrial, municipal, and agricultural pollution of inland waterways and sea coasts; deforestation; soil erosion; soil contamination from improper application of agricultural chemicals; scattered areas of sometimes intense radioactive contamination; ground water contamination from toxic waste.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Wetlands and Whaling. **Has signed, but not ratified:** Climate Change, Air Pollution-Sulphur 94.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999

ENERGY INDUSTRY
Organization: Russia's energy sector is overseen by the Ministry of Energy, except for nuclear power, which is administered by the Ministry of Atomic Energy (Minatom).

Russia's Oil Sector is dominated by large joint-stock companies, although smaller independent producers also produce oil. The major vertically integrated companies include Lukoil, Yukos, Surgutneftegaz, Tyumen Oil (TNK), Tatneft, Sibneft, Slavneft, and Rosneft. Transneft has a monopoly over crude oil transport, while Transnefteprodukt transports petroleum products.

Russia's Natural Gas Sector is dominated by the joint-stock company Gazprom, which is 38% owned by the Russian government. Gazprom produces over 90% of the country's natural gas and also controls Russia's pipeline network. Itera has gained a foothold in the natural gas sector as Russia's second-largest natural gas exporter.

Russia's Coal Sector, formerly operated by RosUgol, a government-owned holding company that was organized along regional lines, has been restructured, with many unprofitable mines closed down, RosUgol eliminated, and the remaining efficient mines privatized. Kuzbassrazrezugol and Krasnoyarskugol were Russia's biggest coal producers in 2001.

Russia's Electricity Sector is operated by the joint-stock company Unified Energy Systems (UES), which is majority state-owned. UES controls approximately 70% of the country's distribution system, 21 thermal power plants, 8 nuclear power plants, and oversees the country's 72 regional electricity companies, known as *energos*.

Major Producing Oil Fields: Samotlor, Romashkino, Mamontov, Fedorov, Lyantor, Arlan, Krasnolenin, Vatyegan, Sutormin

Major Oil Terminals: Novorossiisk (Black Sea), Tuapse (Black Sea), Primorsk (Baltic Sea); Russia also uses ports at Ventspils (Latvia), Odesa (Ukraine), Klaipeda (Lithuania), and Butinge (Lithuania)

Major Oil Export Pipelines outside the Commonwealth of Independent States: Friendship (Druzhba) (1.2 million bbl/d nominal capacity)

Major Oil Refineries (1/1/02E) (Capacity in bbl/d): Omsk (566,000), Angarsk (441,000), Nizhniy Novgorod (438,000), Grozny (390,000), Kirishi (388,000), Novo-Ufa (380,000), Ryazan (361,000), Novo-Kuibishev (309,000), Yaroslavl (290,000), Perm (279,000), Ufaneftekhim (251,000), Salavatnefteorgsintez (247,000), Moscow (243,000), Ufa (235,000), Syzran (211,000), Volgograd (200,000), Saratov (177,000), Orsk (159,000), Samara-Kuibishev (154,000), Achinsk (147,000), Ukhta (127,000), Nizhnekamsk (120,000), Komsomolsk (108,000)

Major Foreign Oil Company Involvement: Agip, BP, British Gas, ChevronTexaco, Statoil, Conoco, ExxonMobil, Neste Oy, Norsk Hydro, McDermott, Mitsubishi, Mitsui, Royal Dutch/Shell, and TotalFina Elf.

Major Producing Natural Gas Fields: Urengoy, Yamburg, Medvezh, Orenburg, Severo Urengoy, Vyngapurov

Major Natural Gas Export Pipelines outside the Commonwealth of Independent States (Capacity): Brotherhood (*Bratrstvo*), Progress, and Union (*Soyuz*) (to Europe, via Ukraine) (1 Tcf each); Northern Lights (0.8 Tcf) (to Europe, via Belarus and Ukraine), Volga/Urals-Vyborg (to Finland) (0.1 Tcf); Yamal (to Europe, via Belarus) (1.0 Tcf); Blue Stream (0.56 Tcf) (to Turkey, under construction)

Major Coal Producing Basins: Chelyabinsk, Kansk-Achinsk, Kuznetsk, Lena, Moscow, Pechora, Raychikhinsk, South Yakutia, Taymyr, Zyryanka

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Sources for this report include: Agence France Presse, Asia Pulse, Associated Press, BBC Monitoring International Reports, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, Current Digest of the Post-Soviet Press, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, Energy Day, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Gas Connections, Hart's European Fuel News, Interfax News Agency, The International Herald

Tribune, International Petroleum Finance, ITAR-TASS News Agency, Mining & Metals Report, The Moscow Times, Oil and Gas Journal, Petroleum Economist, Petroleum Report, Platt's International Coal Report, Platt's Oilgram News, Polish News Bulletin, PR Newswire, Project Finance, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, Russian Economic News, The Russian Oil & Gas Report, Turkish Daily News, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, Warsaw Business Journal, World Gas Intelligence, and World Markets Online.

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July 2002

Kazakhstan: Oil and Natural Gas Exports

OIL EXPORTS

Kazakhstan is second to Russia in terms of net oil exports from the Newly Independent States (NIS). Kazakhstan's decision to open its oil sector to foreign investment after the country became independent in 1991 led to the formation of a number of international consortiums developing major oil projects, and the increased oil output from these joint ventures and production-sharing agreements has boosted the country's net oil exports substantially during the past decade.

After totaling just 129,900 bbl/d in net oil exports in 1992, Kazakhstan registered an average of 631,000 bbl/d in net oil exports in 2001. The 631,000 bbl/d in net exports, up from 551,600 bbl/d in 2000, meant that Kazakhstan exported approximately 78% of its total oil production from 2001 (811,000 bb/d). In 2002, Kazakh oil production is projected to surpass 900,000 bbl/d, and Kazakh Prime Minister Imangali Tasmagambetov has said that the country's net oil exports will top 700,000 bbl/d this year. In addition, Kazakhstan's oil production and net oil exports are certain to increase in the next decade as new export options are brought onstream.

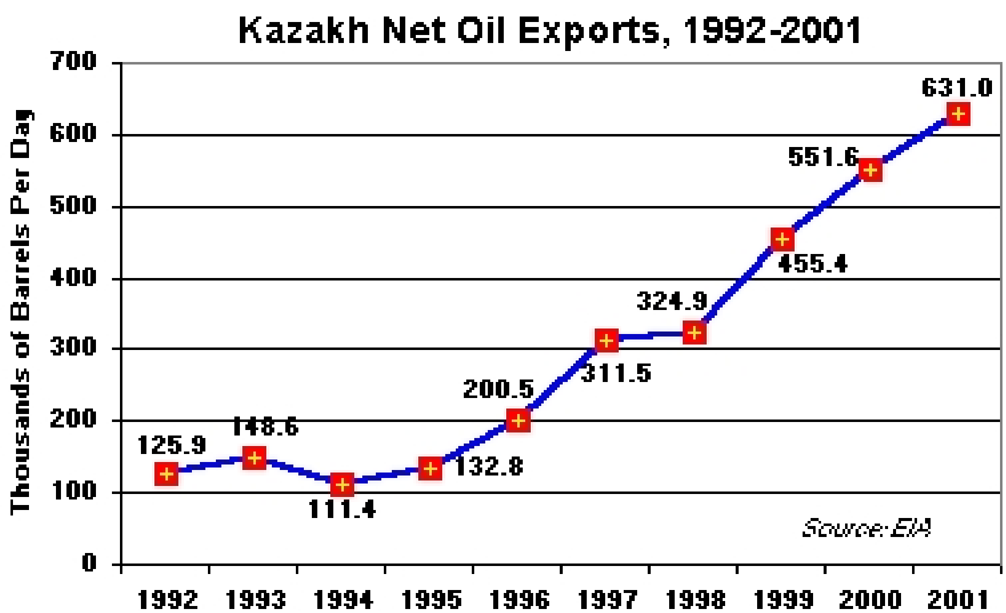
Although Kazakhstan is not a member of the Organization of Petroleum Exporting Countries (OPEC), the country gained observer status in 2001. With the decline in world oil prices in the second half of 2001, OPEC sought to prevent a price collapse and to shore up petroleum demand by limiting production. OPEC members agreed to cut oil exports from January 1, 2002, by 1.5 million bbl/d, contingent on major non-OPEC producers cutting their collective output by 500,000 bbl/d.

Kazakhstan did not receive an official request by OPEC to cut its oil production in 2002, but the country's planned hike in oil production and oil exports is beginning to put it at odds with OPEC, which extended its export cut on July 1, 2002. Kazakhstan is looking to increase its oil production over 1 million bbl/d in 2003, and net oil exports from the country are expected to rise with the expanded capacity of the recently launched Caspian Pipeline Consortium (CPC) export pipeline. Kazakhstan is heavily reliant on oil export revenues; the country's 2002 budget is based on average annual oil prices of $19 per barrel.

Export Route Options

Kazakhstan has over 4,000 miles of oil pipelines and 39 pumping stations. Kazmunaigaz, the new 100% state-owned national oil and natural gas company, assumed management control of Kazakhstan's pipelines when it was formed in February 2002. KazTransOil, which merged with TransNefteGaz to form Kazmunaigaz, is the pipeline monopoly in Kazakhstan, transporting about 80% of the oil produced in the country. KazTransOil pumped an average of 570,000 bbl/d through its pipeline system in the first quarter of 2002, down 9% from the same time period last year. The company attributed the decline to additional Tengiz oil that was transported via the CPC pipeline system, which is not part of the KazTransOil system.

Russia is Kazakhstan's primary export outlet, with Kazakh oil transiting Russia via Kazakhstan's three export pipelines, by barge, and by rail en route to world markets. Kazakhstan exports its oil via the Atyrau-Samara pipeline, which links to Russia's pipeline system, via the Kenkyak-Orsk pipeline, which transports oil to a Russian refinery in Orsk, and via the new CPC export pipeline from Kazakhstan's Tengiz oil field to Russia's Black Sea terminal at the port of Novorossiisk. The CPC pipeline, which became operational in March 2001, is Kazakhstan's first direct export route to world markets.



In June 2002, Kazakhstan and Russia finalized an inter-governmental agreement that makes Kazakhstan eligible to transport up to 350,000 bbl/d through the Russian pipeline system in 2002. The agreement covers the Russian system operated by Transneft, the Russian pipeline monopoly, including the Baltic Pipeline System (BPS), the Atyrau-Samara pipeline, the Baku-Novorossiisk pipeline, and the Makhachkala port, but it does not include the CPC pipeline. Under the agreement, Kazakhstan will guarantee transit of at least 300,000 bbl/d through the Atyrau-Samara pipeline and at least 50,000 bbl/d via Makhachakala and the Baku-Novorossiisk pipeline. Overall, Kazakh oil exports transiting Russia could reach 750,000 bbl/d in 2002.

Tengiz-Novorossiisk Pipeline

In March 2001, the CPC commissioned its $2.5 billion, 1.34 million-bbl/d-capacity pipeline, sending oil flowing 990 miles from Tengiz to Novorossiisk. After several customs problems and technical delays, the first oil was loaded onto a tanker in Novorossiisk in October 2001, and in November 2001, CPC shareholders decided on a transportation tariff of $26.32 per 1,000 tons ($3.59 per barrel) per 100 kilometers (62.5 miles). The CPC exported approximately 240,000 bbl/d in April 2002, with volumes expected to rise to 400,000 bbl/d by the end of 2002 once additional pumping stations and pipeline links are completed.

Preliminary plans are to increase exports to 520,000 bbl/d in 2003, but the pipeline is not scheduled to reach its full capacity until about 2015. ChevronTexaco, which operates the Tengizchevroil joint venture that currently is supplying the majority of to the pipeline, has estimated that during its 35 to 40 year expected life, the pipeline could bring in $8 billion in taxes for Kazakhstan, and development of the Tengiz field and operation of the pipeline would earn about $150 billion for Kazakhstan and Russia.

Since both Kazakh and Russian oil will be piped via the line, creating a new "CPC Blend" of oil, Kazakh and Russian officials created a "quality bank" to compensate higher-quality Kazakh oil exporters whose oil quality is diluted by the new blend. The Tengizchevroil joint venture will transport approximately 240,000 bbl/d via the pipeline in 2002, with future plans to export an additional 120,000 bbl/d per year from the Karachaganak field via the CPC. Hurricane Hydrocarbons, which is developing the Kumkol field in Kazakhstan, had been in negotiations to join the Caspian Pipeline Consortium in order to export up to 64,000 bbl/d via the pipeline, but in June 2002 the company announced it failed to reach an agreement to join the consortium.

Turkish officials have questioned the ability of the Bosporus Straits to handle the planned volume of Kazakh oil to be exported via the CPC pipeline. Turkish officials have expressed environmental concerns that the Straits, already a major chokepoint for oil tankers, cannot handle the strain of additional traffic, which could lead to a tanker collision and an oil spill in the Straits. Although Kazakh officials have argued against limiting oil tanker traffic through the Straits, a number of "Bosporus bypass" options are under consideration or being developed in southeastern Europe. In addition, Ukraine already has constructed a new pipeline, the Odessa-Brody pipeline, specifically to transport oil from the Caspian Sea region to European markets.

Atyrau-Samara Pipeline
Prior to the opening of the CPC pipeline, Kazakhstan's largest oil export line was the Western Kazakhstan pipeline system, which transports oil from fields in Atyrau and Mangistau to Russia. This pipeline system runs 1,800 miles, from Uzen in southwestern Kazakhstan to the Caspian port of Atyrau, before crossing into Russia and linking with Russia's pipeline system at Samara. The pipeline's capacity was recently increased from 240,000 bbl/d to 300,000 bbl/d with the addition of another pumping station.

In recent years, Kazakhstan's exports via the Atyrau-Samara pipeline have been limited by Kazakhstan's annual oil export quota through the Russian pipeline system, which compete with Russian oil exports. Kazakhstan is interested in gaining access to oil terminals in the Baltic Sea for its exports, and Kazakhstan has been ready for a number of years to supply oil to Lithuania, but deliveries have been delayed due to the lack of an agreement with Russia on transportation tariffs. In addition to Kazakhstan's increased production capacity, Russia's interest in the long-term transit of Kazakh oil increased with the opening of Russia's Baltic Pipeline System (BPS) in December 2001. In an effort to fill the BPS and to profit from Kazakh oil transiting its territory, Russia allocated a 100,000 bbl/d quota of Kazakh oil for the BPS.

Other Exports Via Russia

Another export pipeline is the Kenkyak-Orsk line that transports oil from western Kazakhstan to Russia. This pipeline runs from the Aktyubinsk fields to the Orsk refinery in Russia, and has a capacity of 130,000 bbl/d. Kazakhstan and Russia plan to swap 50,000 bbl/d of oil, with Kazakhstan supplying oil to the Orsk refinery in Russia and receiving an equivalent amount through the Omsk-Pavlodar pipeline for processing at the Pavlodar refinery in Kazakhstan.

In addition, Kazakhstan plans to export an additional 50,000 bbl/d of oil in 2002 through the Russian Caspian port of Makhachkala. Oil is exported via the Kazakh port of Aqtau, which underwent a $100 million upgrade in 2000 to increase its handling capacity from 60,000 bbl/d to 160,000 bbl/d, and barged to Makhachkala before joining the Makhachkala-Tikhorestk-Novorossiisk pipeline. Although the Aqtau port is expected to experience a drop in transshipment levels with the opening of the CPC pipeline, it will remain a strategically important route for the export of oil that is not acceptable in quality for the CPC pipeline or the Atyrau-Samara pipeline.

Additional Export Options

With the launch of the CPC pipeline and the expansion of the Atyrau line, Kazakhstan's pipeline export capacity has increased to nearly 1 million bbl/d, which should meet export needs until about 2007. Kazakhstan is interested in diversifying its oil export routes, and as such, additional oil export pipeline options from the Caspian Sea region are being explored. Kazakh officials have said that they would not make a decision on another main route for the country's oil exports until results of test wells in the Caspian Sea are known.

Trans-Caspian oil pipelines could be built that would connect with other export pipelines, such as the proposed Main Export Pipeline from Baku (Azerbaijan) to Ceyhan (Turkey). ExxonMobil, Royal Dutch/Shell, and ChevronTexaco are conducting a feasibility study on building a pipeline from Aqtau to Baku that would traverse the Caspian Sea bed from north to south. Kazakhstan also has discussed shipping oil from its Kumkol field to Turkmenistan's Caspian port of Turkmenbashi and then shipping it to Azerbaijan for export.

Several proposed routes for Kazakhstan could bring oil towards markets in Asia instead of to European markets. One proposed pipeline would carry Kazakh oil via Turkmenistan to outlets in Iran and the Persian Gulf. In April 2002, Kazakh President Nursultan Nazarbayev, in a meeting with Iranian President Mohammed Khatami, stated that an oil pipeline route through Iran would be the most economical way to export Kazakh oil. Kazmunaigaz currently is in talks with French-Belgian TotalFinaElf to prepare a feasibility study for a pipeline from Kazakhstan to Iran.

Another option is for Kazakhstan to implement an existing oil swap arrangement with Iran. Under a 1996 agreement, up to 120,000 bbl/d of Kazakh oil was to be delivered by tanker via the Caspian Sea to the

Iranian port of Neka, where it would travel by pipeline to a refinery at Tabriz to be refined and consumed locally. In exchange, Kazakhstan would receive a similar volume of crude ready for export at an Iranian port in the Persian Gulf. Kazakhstan and Iran have been trying to negotiate a supply deal for years, but previously Kazakh crude has proved incompatible with Iranian refineries and there have been disagreements over price.

In the first quarter of 2002, Kazakhstan began making test deliveries to Neka of about 1,600 bbl/d. Kazakh officials hoped to increase the swaps to 17,000 bbl/d, but that appears to be unlikely at this time. In addition, a major problem with the Iran route is U.S. sanctions against Iran. U.S. oil firms are prohibited from investing in the Iranian oil sector, and the Iran-Libya Sanctions Act (ILSA) seeks to penalize non-U.S. firms from doing business with Iran. Previous cases of swap arrangements--between Turkmenistan and Iran--have been judged to violate ILSA, and it remains to be seen whether Kazakhstan will choose to implement its swap arrangement with Iran further.

Kazakhstan also is considering the Chinese market. Kazakhstan exported 50,000 bbl/d to China by rail in 1999, and Tengizchevroil has made test deliveries to China by rail. In June 1997, the China National Petroleum Corporation signed an agreement with Kazakhstan for a proposed $3.5 billion, 1,800-mile pipeline to China that would be financed by China. A feasibility study for the pipeline was undertaken, but the study was halted near its completion date. In order to make the project economically feasible, Kazakhstan would have to guarantee 500,000 bbl/d per year through the pipeline, a level to which Kazakhstan said it could not commit.

Recently, progress has reportedly been made on a Trans-Asian oil export pipeline linking Kazakhstan and India. The preferred route would bypass the volatile countries of Pakistan and Afghanistan, although this would make the project more expensive. The pipeline apparently would pass through the city of Kashi in northwestern China and then across the Siachen Glacier into Indian Kashmir.

NATURAL GAS EXPORT OPTIONS

Although Kazakhstan is currently a net importer of natural gas, with the expected increase in the country's natural gas production, Kazakh officials project that the country's natural gas exports could reach 1.2 trillion cubic feet (Tcf) per year by 2015. However, Kazakhstan's natural gas-producing areas are not linked to its internal pipeline network, and the country suffers from a lack of export infrastructure. In order to reach its natural gas exporting potential, therefore, Kazakhstan must either negotiate to export via the Russian natural gas pipeline system or develop new ways of getting its natural gas to customers.

In June 2002, Kazakhstan's Kazmunaigaz and Russia's natural gas monopoly Gazprom announced the formation of a joint venture, KazRosGaz, that will start by transporting 124 billion cubic feet (Bcf) of natural gas through the Russian pipeline system, with volumes rising as Kazakh natural gas production increases. The deal will allow Kazakhstan to receive access to the Russian pipeline system, where previously Kazakhstan had to sell its natural gas on the border with Russia.

Karachaganak Natural Gas Exports
Kazakhstan's giant Karachaganak field, located close to the Russian border and 240 miles from Russia's Orenburg natural gas field, is believed to contain 16 Tcf of natural gas. Peak production at the field is expected to reach 353 Bcf annually, but the development of the field has been hampered because the former Soviet Union intended for this natural gas to be processed at Orenburg in Russia and exported via pipelines from Russia.

Since Kazakh natural gas now is a competitor with Russian natural gas, the Orenburg plant has accepted only a fraction of Karachaganak's potential output. In addition, although Russia's Gazprom originally agreed to take a 15% stake in the consortium developing Karachaganak in exchange for processing and exporting the natural gas, it has since left the project. As a result, Kazakhstan has planned to build a new, $600 million gas processing plant at Karachaganak to process the condensate.

Offshore Natural Gas Export Options
Kazakhstan's offshore natural gas fields, notably Kashagan, will need similar infrastructure investments. Kazakh President Nursultan Nazarbayev has stipulated that natural gas from the field must be captured rather than flared. Commercial production of oil and associated gas at the Kashagan deposit is expected to begin in 2005, but transporting the natural gas is likely to prove expensive. Since the infrastructure to transport the natural gas currently does not exist, analysts agree that Italy's ENI, the operator of the Kashagan field, almost certainly will have to come to an agreement with Russia's Gazprom, which has a vast pipeline network, in order to transport and export the field's natural gas.

In addition, Kazakhoil (now Kazmunaigaz) and Phillips, two of the partners in Agip KCO, the international consortium that is developing Kashagan, have agreed to conduct a feasibility study on the construction of a proposed $500 million liquefied natural gas (LNG) plant at Atyrau. The proposed plant would be built by 2004, and LNG would be transported to consumers by rail. From there, LNG will be barged across the Caspian to Baku, then transported using rail and sections of the natural gas pipelines in Georgia to Batumi before continuing on to Turkey and other Mediterranean customers.

Additional Natural Gas Export Options
Other natural gas export pipeline options from the Caspian Sea region also are being considered. One option is a proposed 5,000-mile pipeline that would bring 1 Tcf of natural gas annually from Central Asia across Kazakhstan to China. The pipeline would start in Turkmenistan and traverse Uzbekistan and Kazakhstan before traveling the length of China--a 4,161-mile journey to Xinjiang. A preliminary feasibility study of this route was conducted by Exxon, Mitsubishi and China National Petroleum Co., but the estimated $10 billion cost, along with logistical difficulties related to building the world's longest pipeline, means that the pipeline is unlikely to be constructed.

Another alternative is to export natural gas westwards to Turkey and other European markets. In December 1998, Royal Dutch/Shell, Chevron, and Mobil signed an agreement with Kazakhstan to conduct a feasibility study for twin oil and natural gas pipelines that would pass across the Caspian Sea from Kazakhstan to Baku.

Natural Gas Transit

Kazakhstan already is a transit route for natural gas from Turkmenistan and Uzbekistan flowing to Russia and on to other markets in the former Soviet Union via the Central Asia-Center Pipeline and the Bukhara-Urals Pipeline. In addition, Russian natural gas flowing westward crosses into Kazakh territory in the northwest of the country. Kazakhstan earns approximately $400 million per year from natural gas transit fees.

The majority of Turkmen and Uzbek natural gas that transits Kazakhstan is pumped north along the Central Asia-Center natural gas pipeline. However, deterioration of compressor stations and various stretches of the pipeline have eroded the pipeline system's 3.53 Tcf per year capacity: according to Turkmen officials, capacity on the Central Asia-Center pipeline is only about 2.4 Tcf to 2.5 Tcf presently due to a lack of maintenance and repair.

With Turkmen and Uzbek planning to increase natural gas exports via Kazakhstan, the Bukhara-Urals pipeline has been pressed into service. In March 2001, natural gas transit started on the previously inactive pipeline, with approximately 200 Bcf exported via the pipeline in 2001. Kazakhstan invested about $20 million in modernizing its section of the Bukhara-Urals pipeline system in 2000.

Kazakhstan needs about $360 million to restore its section of the Center Asia-Center pipeline to enable the country to handle the increased transit volumes from Turkmenistan and Uzbekistan. Increased capacity on the pipeline also will be necessary for Kazakhstan to export its own natural gas from Kashagan and Karachaganak.

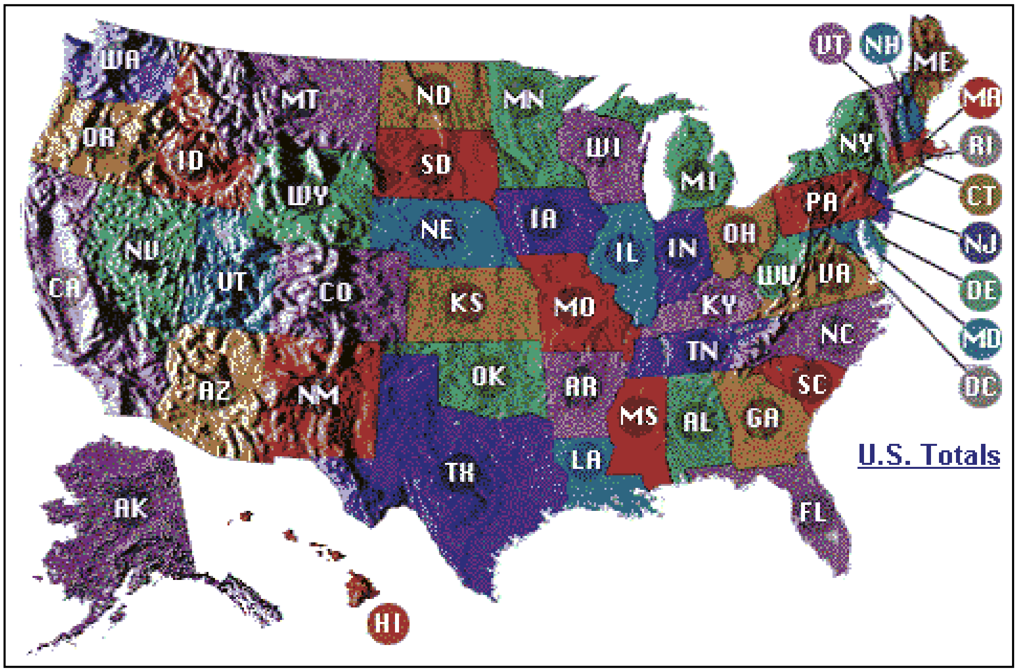
Return to Kazakhstan Country Analysis Brief

May 2002

United States of America

The United States of America is the world's largest energy producer, consumer, and net importer. It also ranks twelfth worldwide in reserves of oil, sixth in natural gas, and first in coal.

Information contained in this report is the best available as of May 2002 and is subject to change. For the latest monthly U.S. outlook by the Energy Information Administration, please see the "Short-Term Energy Outlook".



GENERAL BACKGROUND
As of early May 2002, the U.S. economy appeared to be rebounding somewhat, following what may turn out to be one of the mildest recessions (or not a recession at all) in U.S. history. One possible factor which could harm the U.S. economic recovery is high oil prices. Also, in early May, the U.S. unemployment rate hit a seven-year high, moving up

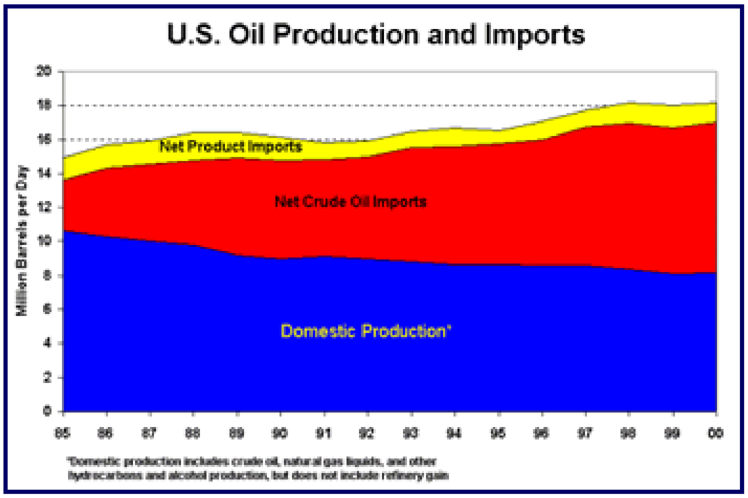
0.3% to 6%. The recent difficulties experienced by the U.S. economy follow a period during the mid- and late-1990s of strong growth, low inflation, low unemployment, rapid productivity growth, and a booming stock market. Real (inflation adjusted) U.S. gross domestic product (GDP) growth for 2001 now is expected at 1.6%, up from 1.2% growth in 2001. Real GDP grew at a 5.8% rate in the first quarter of 2002, after growing by only 1.7% in the fourth quarter of 2001 and falling by 1.3% in the third quarter. Part of this recent growth appears to have been driven by businesses restocking inventories, and part by increased government spending. In addition, the US Federal Reserve moved aggressively to cut interest rates in response to the September 11, 2001 terrorist attack on the United States, and the U.S. Congress passed an economic stimulus package in March 2002.

For FY 2000, the federal budget ran a surplus of around $237 billion, higher than previously forecast. For 2001, the Congressional Budget Office (CBO) as late as spring was projecting a possibly even higher surplus for FY 2001. However, a combination of factors (economic slowdown, tax rebates) reduced this projected surplus significantly, with a deficit now considered likely in FY 2002. Meanwhile, the U.S. merchandise trade deficit surged to $427 billion in 2001. This deficit mainly reflected the strength of the U.S. economy (and a strong dollar) relative to major U.S. trading partners. The current account deficit now is running at over 4% of GDP, compared to 1.7% in 1997.

January 20, 2001, George W. Bush was inaugurated as President of the United States, succeeding Bill Clinton. In mid-May 2001, the Bush administration issued a series of energy policy recommendations as part of its new National Energy Policy Report, developed by a task force led by Vice President Dick Cheney. In August 2001, the U.S. House of Representatives passed an energy bill (the "Securing America's Future Energy" -- SAFE -- Act of 2001) which contained many of the energy plan's recommendations. In April 2002, the U.S. Senate passed its own version of an energy bill, which must now be reconciled with the House version.

OIL

The United States had 22.0 billion barrels of proved oil reserves as of January 1, 2002, twelfth highest in the world. These reserves are concentrated overwhelmingly (over 80%) in four states -- Texas (25% including the state's reserves in the Gulf of Mexico), Alaska (24%), California (21%), and Louisiana (14% including the state's reserves in the Gulf of Mexico). U.S. proven oil reserves have declined by around 20% since 1990, with the largest single-year decline (1.6 billion barrels) occurring in 1991.



During 2001, the United States produced around 8.1 million barrels per day (MMBD) of oil, of which 5.9 MMBD was crude oil, and the rest natural gas liquids and other liquids. U.S. total oil production in 2001 was down sharply (around 2.5 MMBD, or 24%) from the 10.6 MMBD averaged in 1985. U.S. crude oil production, which declined following the oil price collapse of late 1985/early 1986, leveled off in the mid-1990s, and began falling again following the sharp decline in oil prices of late 1997/early 1998. With the rebound in world oil prices since March 1999, U.S. crude production basically leveled off once again in 2000 and 2001. U.S. crude production for 2001 was the second lowest since 1950. In 2000, there were around 534,000 producing oil wells in the United States, the vast majority of which are considered "marginal" or "stripper" wells, generally producing only a few barrels per day of oil. For 2001, top oil producing areas included the Gulf of Mexico, Texas onshore, Alaska's North Slope, California, Louisiana, Oklahoma, and Wyoming.

Domestic oil exploration and development spending by U.S. major oil companies also rebounded during 2001 from the deep cuts made during the oil price collapse of 1997/1998. Improved technology and new or increased offshore production in the Gulf of Mexico (including at deepwater areas beyond the continental shelf) also could help matters. In 2000, deepwater production in the Gulf of Mexico for the first time surpassed shallow water production. In January 2000, Chevron and Shell -- the largest producer in the Gulf of Mexico -- signed an agreement to share drilling rigs and to drill exploratory wells jointly in the deep-water Gulf of Mexico. In March 2002, a US government lease sale for the central Gulf of Mexico produced bids totaling $363 million. Bidders included Dominion Exploration and Production, Spinnaker Exploration, BP, Chevron, Kerr-McGee, BHP Petroleum, Nexen Petroleum Offshore USA, and Conoco. Overall, production from deepwater areas of the Gulf of Mexico has been increasing rapidly, with deepwater wells accounting for about two-thirds of total US Gulf output. Large fields include ExxonMobil's Hoover-Diana development (scheduled to start up this year), and BP's Atlantis, Crazy Horse (the largest single field every discovered in the Gulf of Mexico), Crosby, Holstein, King, King's Peak, Mad Dog, Marlin, and Nakika fields. BP has stated that it plans to accelerate its deepwater Gulf of Mexico production plans, possibly including construction of a $1-billion deep-sea pipeline, and to increase its production from 200,000 bbl/d currently to 750,000 bbl/d in 2007. This will require billions of dollars worth of investment.

Crude oil production in the lower 48 states is expected to remain essentially flat through 2002, as is Alaskan crude production, which accounts for around 17% of the U.S. total. Alaskan production is down about 50% from the 2.0 MMBD reached during the peak year of 1988. Most of Alaska's oil output comes from the giant Prudhoe Bay Field, and is transported via the Alyeska pipeline. A new oilfield, known as Alpine (owned 78% by Phillips Petroleum, 22% by Anadarko), began production in November 2000. Alpine represents the largest North American onshore oil discovery in a decade, and was producing 80,000 bbl/d of high quality, light crude oil by the end of 2000. Production at Alpine could rise to 120,000 bbl/d with tie-ins to the Nanuk and Fiord satellite fields. Phillips has been the largest oil producer in Alaska since acquiring Arco's Alaska fields in early 2000. In November 2000, two oil and natural gas lease sales conducted by the State of Alaska drew bids worth $11 million for offshore tracts in the Beaufort Sea and onshore in the North Slope. In another piece of news from Alaska, the critical Trans-Alaska Pipeline System (TAPS) shut down in early October after being punctured by a gunshot. The TAPS resumed operations on October 8, 2001.

In early 2000, the Energy Information Administration (EIA), in response to a Congressional request, issued a report on potential oil reserves and production from the Arctic National Wildlife Refuge (ANWR). The report, which cited a 1998 U.S. Geological Survey study of ANWR oil resources, projected that for the mean resource case (10.3 billion barrels technically recoverable), ANWR peak production rates could range from 1.0 to 1.35 MMBD, with initial ANWR production possibly beginning around 2010, and peak production 20-30 years after that.

According to Baker Hughes Inc., which has tallied weekly U.S. drilling activity since 1940, domestic oil and natural gas drilling has rebounded sharply since the low point of 488 reached in late April 1999 following the oil price collapse of late 1997. In mid-October 2001, for instance, the U.S. weekly "rig count" reached the 1,141 mark (933 for natural gas and 208 for oil), down slightly from earlier in the year but still close to the highest number since late 1990. Another interesting characteristic of the U.S. rig count is that natural gas rigs now outnumber oil rigs by more than three-fold. Historically, U.S. drilling activity peaked in 1981, with a total of 43,598 oil wells (and 20,166 natural gas wells) drilled in that year. For 2000, a total of 4,731 oil wells (and 15,206 natural gas wells) were drilled in the United States, up from 4,087 oil wells (and 10,513 natural gas wells) in 1999. Total natural gas wells drilled in 2000 were the most since 1984, prompted by record-high prices and surging natural gas demand.

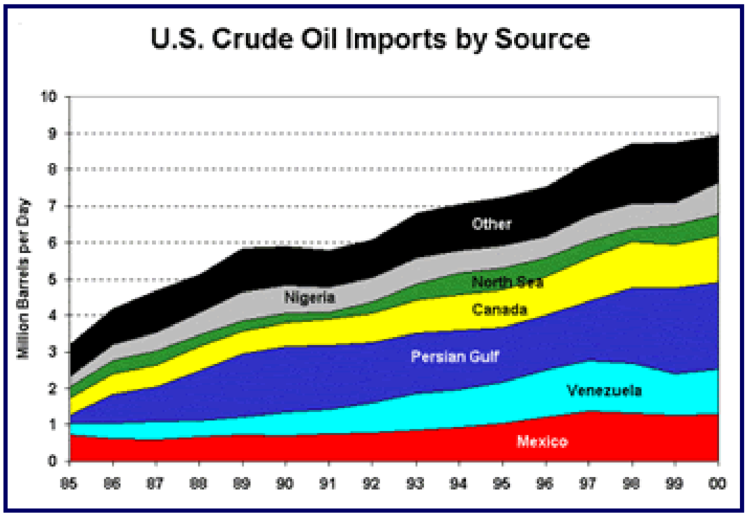
Twenty-two major energy companies reported overall net income (excluding unusual items) of $4.6 billion on revenues during the fourth quarter of 2001 (Q401). This level of net income represented a 65% decrease relative to the fourth quarter of 2000 (Q400) (see EIA's "Performance Profiles for Major Energy Producers 2000"). Foreign upstream oil and natural gas production operations accounted for $2.0 billion of net income, followed by domestic upstream oil and natural gas production operations ($1.8 billion) and worldwide downstream natural gas and power operations ($1.5 billion). Besides the major energy companies, independent oil and natural gas producers, oil field companies and refiner/marketers also reported declines in net income (down 26%) during Q401 compared to Q400. As with the majors, this decline in net income was due to sharp drops during that period in the prices of oil and natural gas.

Consumption/Marketing

The United States consumed an average of 19.6 MMBD of oil in 2001. Of this, 8.6 MMBD (or 44% of the total) was motor gasoline, 4.7 MMBD (24%) "other oils," 4.0 MMBD (20%) distillate fuel oil, 1.7 MMBD (8%) jet fuel, and 0.8 million bbl/d (4%) residual fuel oil. U.S. oil demand is expected to remain roughly flat for 2002, and then begin increasing again in 2003. Following the September 11 terrorist attacks, U.S. jet fuel demand fell sharply. For the first three months of 2002, U.S. jet fuel consumption was down 11% compared to the same period in 2001.

Imports/Exports

The United States had *total gross oil* (crude and products) imports of an estimated 11.6 MMBD during 2001, representing around 59% of total U.S. oil demand. Around 47% of this oil came from OPEC nations, with Persian Gulf sources accounting for about 23% of U.S. oil imports during the year. Overall, the top suppliers of oil to the United States during 2001 were Canada (1.8 MMBD), Saudi Arabia (1.7 MMBD), Venezuela (1.5 MMBD), and Mexico (1.4 MMBD). During 2001, about 48% of U.S. *gross crude oil* imports came from the Western Hemisphere (19% from South America, 15% from Mexico, 14% from Canada), while 30% came from the Persian Gulf region (18% from Saudi Arabia, 9% from Iraq, 3% from Kuwait).



U.S. Energy Sanctions Issues

The United States maintains energy sanctions against several countries, including Iran, Iraq, and Libya (an oil embargo against Serbia was lifted by President Clinton on October 12, 2000). Iraq remains under comprehensive sanctions imposed after its invasion of Kuwait in August 1990. Iran and Libya are affected by the Iran-Libya Sanctions Act (ILSA), passed unanimously by the U.S. Congress and signed into law by President Clinton in August 1996. ILSA imposes mandatory and discretionary sanctions on non-U.S. companies which invest more than $20 million annually (lowered in August 1997 from $40 million) in the Iranian oil and natural gas sectors. The passage of ILSA was not the first U.S. sanction against Iran. In early 1995, President Clinton signed two Executive Orders which prohibited U.S. companies and their foreign subsidiaries from conducting business with Iran. The Orders also banned any "contract for the financing of the development of petroleum resources located in Iran." On March 13, 2001, President Bush, citing threats posed by Iran to U.S. national security, extended Clinton's two Executive Orders on Iran for another 6 months. On August 3, 2001, President Bush signed into law the ILSA Extension Act of 2001. This Act provides for a 5-year extension of ILSA with amendments that affect certain of the investment provisions.

Attempts by the United States to implement ILSA have run into opposition from a number of foreign governments. The European Union (EU) opposes the enforcement of ILSA sanctions on its members, and on November 22, 1996 passed resolution 2271 directing EU members to not comply with ILSA. On May 18, 1998, the EU and the U.S. reached an agreement on a package of measures to resolve the ILSA dispute at the EU/U.S. Summit in London, but the Summit deal is contingent upon acceptance by the U.S. Congress before full implementation may take place.

On April 5, 1999, following the Libyan handover of two suspects in the 1988 bombing of Pan Am flight 103 to stand trial before a Scottish Court in the Netherlands, the United States modified its Libya sanctions on April 28, 1999 to allow shipments of donated clothing, food and medicine for humanitarian reasons (trade in informational materials such as books and movies is also allowed). However, all other U.S. sanctions against Libya remain in force. On February 1, 2001, one suspect was convicted by the Scottish court, while another was acquitted. The U.S. and British governments both said that they still expected Libya to accept responsibility for the murders, which Libya has said it would not do.

Refining

The United States has experienced a steep decline in refining capacity since 1981. Between 1981 and 1989, the number of U.S. refineries fell from 324 to 204, representing a loss of 3 MMBD in operable capacity, and a concomitant increase in refining capacity utilization from 69 to 86%. Much of this decline resulted from the 1981 deregulation (elimination of price controls and allocations), which effectively removed the major prop from underneath many marginally profitable, often smaller, refineries. Between 1989 and 1992, refining capacity remained roughly stable. Since 1992, over 30 additional, mainly small U.S. refineries have shut down, for a wide variety of reasons (economic, regulatory, etc.). This, combined with higher refinery runs, raised average weekly capacity utilization to 96% in 1998, before falling off to an average 92.7% in 1999. As of October 2001, capacity utilization at U.S. refineries reportedly was averaging around 92%-94%. Although financial, environmental, and legal considerations make it unlikely that new refineries will be built in the United States, expansion at existing refineries likely will increase total U.S. refining capacity in the long-run. EIA reports that nameplate refining capacity has increased by about 700,000 bbl/d between 1997 and 1999.

Since the mid-1980s, several U.S. refiners have joined with foreign (especially Venezuelan) companies in various joint venture arrangements. In 1986, for instance, Venezuela's state oil company PdVSA acquired a 50% interest in Citgo's U.S. refining operation. In 1988, Texaco and Saudi Aramco created Star Enterprise, an integrated refining and marketing operation with three refineries and a network of Texaco gasoline stations. Unocal and PdVSA followed suit in 1989, forming Uno-Ven Co. (in 1997, PdVSA bought out Unocal's share). In late October 1997, Mobil signed an agreement with a PdVSA subsidiary on joint ownership of the 170,000-bbl/d refinery in Chalmette, Louisiana.

Strategic Petroleum Reserve (SPR)

The SPR was officially established on December 22, 1975, when then-President Ford signed the Energy Policy and Conservation Act (EPCA). EPCA declared it to be U.S. policy to establish a petroleum reserve of up to 1 billion barrels. In order to store the reserve oil, the U.S. government in April 1977 acquired several salt caverns along the Gulf of Mexico coastline. The first crude oil was delivered to the SPR on July 21, 1977, and stored at the West Hackberry storage site near Lake Charles, LA. Other major storage sites include: Bryan Mound and Big Hill in Texas; and Bayou Choctaw, the St. James Terminal in Louisiana, with a total storage capacity of 700 million barrels.

The volume of oil stored in the SPR peaked at 592 million barrels in 1994. After selling off $327 million worth of SPR oil in 1996, and $220 million in 1997, the SPR contained around 566 million barrels of oil as of May 1 -- still the largest emergency oil stockpile in the world. However, in relative terms the SPR has shrunk from about 115 days of import replacement in 1985 to around 51 days now. In mid-November 2001, President Bush directed the Department of Energy (DOE) to fill the SPR to its capacity of 700 million barrels in order to "maximize long-term protection against oil supply disruptions." Under the DOE plan, the SPR is to be filled with "royalty in kind" (RIK) oil.

Under EPCA, there is no preset "trigger" for withdrawing oil from the SPR. Instead, the President determines that drawdown is required by "a severe energy supply interruption or by obligations of the United States" under the International Energy Agency. EPCA defines a "severe energy supply interruption" as one which: 1) "is, or is likely to be, of significant scope and duration, and of an emergency nature;" 2) "may cause major adverse impact on national safety or the national economy" (including an oil price spike); and 3) "results, or is likely to result, from an interruption in the supply of imported petroleum products, or from sabotage or an act of God."

Should the President decide to order an emergency drawdown of the SPR, oil would be distributed mainly by competitive sale to the highest bidder(s). This would be accomplished in a 4-step process, including a "Notice of Sale," receipt of bids, selection of bidders, and finally delivery of oil. Today, the SPR can withdraw oil at a maximum sustained rate of 4.1-4.2 MMBD for a 90-day period (lower after that).

On September 22, 2000, President Clinton authorized the release of 30 million barrels of oil from the SPR over 30 days in an attempt to bolster U.S. oil supplies and to alleviate possible shortages of heating oil during the upcoming winter. The release took the form of a "swap" (bidding results were announced on October 4) in which crude oil volumes drawn from the SPR is to be replaced by the recipients at a later date. Oil prices fell in anticipation of, and in reaction to, the news.

Oil Mergers and Acquisitions

Pushed in part by low oil prices during 1998 and into early 1999, but also by the desire for oil reserves, cost cutting, and higher refining/marketing shares, merger activity in the oil business accelerated sharply over the past 2-3 years. The largest merger/acquisition announcements came from BP and Amoco, Exxon and Mobil, BP Amoco and ARCO, and, most recently, Chevron and Texaco. BP and Amoco completed their $53-billion merger on December 31, 1998, a day after the deal received regulatory approval from the U.S. Federal Trade Commission (FTC), subject to certain conditions.

On April 13, 2000, the FTC approved the $27.6-billion BP Amoco-ARCO deal. This followed the March 15, 2000 announcement by Phillips Petroleum that it had agreed to purchase ARCO's assets in Alaska for $6.5 billion. The sale was made as part of an effort to secure approval from the FTC. On the same day, the FTC announced that it had suspended its antitrust lawsuit seeking to block the merger, citing progress in talks with the companies involved. Among other issues, the FTC was concerned that the BP Amoco-ARCO merger would control about 75% of Alaskan North Slope crude oil output and over 70% of the critically important TAPS line, potentially hurting consumers on the U.S. west coast. BP Amoco agreed to sell some pipeline and oil storage holdings in Cushing, Oklahoma. The new company (now called BP) will rank in the top three private oil companies in the world, along with ExxonMobil and Royal Dutch/Shell.

Meanwhile, the $81-billion merger between Exxon and Mobil, which formed the world's largest privately owned petroleum company (in terms of revenues), was approved by the FTC on December 1, 1999, subject to the divestiture of 2,400 service stations and other assets (on December 3, 1999, 1,740 of these stations were sold to Tosco, the largest U.S. independent oil refiner). In a related development, in April 2000, Duke Energy said that it had agreed to acquire Mobil's European natural gas trading and marketing business. The sale of Mobil's natural gas operations in Europe was required by the European Commission as part of its approval of the ExxonMobil merger.

On October 16, 2000, another major oil industry merger/acquisition was announced, this time between Chevron and Texaco. According to the announcement, Chevron is to buy Texaco for $35 billion in stock, creating the world's fourth largest energy company (behind ExxonMobil, Shell, and BP). The deal received regulatory approval in early October 2001, and was approved by shareholders of the two companies on October 9, creating ChevronTexaco.

On November 3, 2000, Russia's Lukoil announced that it intended to purchase Getty Petroleum Marketing for $71 million. Lukoil eventually intends to switch Getty's 1,300 retail outlets in the Northeastern and Middle Atlantic states to the Lukoil brand name. The purchase represents the first takeover of a publicly traded U.S. company by a Russian firm. In late January 2001, Getty shareholders approved the the buyout.

On November 19, 2001, the *Wall Street Journal* reported that Phillips Petroleum and Conoco Inc. agreed to merge in a $15.2 billion transaction. This transaction would create a company (to be called ConocoPhillips) that will be the sixth-largest oil and gas company in the world, the largest U.S. refiner, and the third-largest U.S.-based energy company.

On March 26, 2002, *The Wall Street Journal* reported that Shell Oil Co. agreed to acquire

Pennzoil-Quaker State Co. for $1.8 billion and to assume $1.1 billion of Pennzoil-Quaker State debt. *The Wall Street Journal* noted that this transaction combines Shell's 3% share of the U.S. market for passenger car motor oil with Pennzoil-Quaker State's 35% share. Shell also adds Pennzoil-Quaker State's 46,200 barrels-per-day Shreveport, Louisiana refinery and more than 2,000 Jiffy Lube outlets.

Besides these large mergers, several defensive mergers among smaller, independent oil companies also have been unveiled recently, including Kerr-McGee Corp.'s (KMG) $1.86-billion takeover of Oryx Energy Co. (ORX), and an agreement between Seagull Energy Corp. (SGO) and Ocean Energy Inc. (OEI) to merge in a $1.1-billion deal. On July 14, 2000, Anadarko Petroleum announced the closing of its merger transaction with the Union Pacific Resources Group. Union Pacific became a wholly owned subsidiary of Anadarko, creating one of the largest U.S. independent oil and natural gas companies. In January 2001, Amerada Hess announced that it was withdrawing a $3.5-billion offer to purchase Britain's Lasmo P.L.C., a move which would have created a "super-independent" oil company. Instead, Lasmo was purchased by Italy's ENI for $4 billion.

Due to low profitability in the refining/marketing line of business, U.S. integrated major energy companies began a process during the 1990s of selective refining/marketing divestiture, and numerous U.S. refineries were shut down. Among independent refiners, growth largely has been concentrated in the following group of companies: Citgo/PDV America, Clark Refining and Marketing, Diamond Shamrock (merged with Ultramar during 1996, creating Ultramar Diamond Shamrock), Koch Industries, Tesoro Petroleum, Ultramar, and Valero Energy. In May 2001, Valero agreed to acquire Ultramar Diamond Shamrock for $6 billion. Another company, Tosco Corporation, was purchased by Phillips Petroleum for $7.5 billion in September 2001, creating the second largest refining group in the United States, behind ExxonMobil.

NATURAL GAS

As of January 1, 2002, the United States had estimated proven natural gas reserves of 177 trillion cubic feet (Tcf), or 3.2% of world reserves (6th in the world). In 2001, the United States produced 19.1 Tcf of dry natural gas. Also during 2001, the United States consumed 22.7 Tcf and imported (net) around 3.5 Tcf of natural gas, mainly from Canada. Overall, the United States depends on natural gas for about 23% of its total primary energy requirements (oil accounts for around 39% and coal for 23%).

Natural gas wellhead prices reaching record highs of nearly $10.00 per thousand cubic feet (mcf) in late 2000/early 2001, but fell sharply soon thereafter to around $2.50 per mcf. Natural gas spot prices have been hovering over $3.00 per thousand cubic feet since March 2002**.** This may be explained in part by 1) the unusual weather patterns in March and April: March and much of April were colder than normal, but in part of April, an unusual and intense heat wave occurred, resulting in a surge in electricity demand for cooling, which in turn led to increased demand for natural gas in the power sector; 2) the rising price of crude oil due to a general concern in the market in response to the current tensions in the Middle East; 3) the sense that the U.S. economy is recovering at a more rapid pace than previously expected; 4) the increased capacity and the planned new capacity of gas-burning power plants; and 5) concerns that natural gas production, as well as drilling and exploration, have recently fallen off, resulting in a less rosy supply outlook for the near term. For 2002, assuming normal weather and barring any major supply disruptions, the annual average natural gas wellhead price is projected to be about $2.80 per mcf compared to over $4.00 per mcf last year.

Natural Gas Production

Domestic natural gas production is projected to increase through 2002 as the effects of sharply increased drilling over the past year begin to be felt. Exploration and production budgets for many natural gas producers increased sharply in 2000, spurred by higher prices and greatly improved current and expected revenues.

U.S. natural gas production (and net imports, mainly from Canada) is likely to increase sharply over the next two decades in response to strong demand, abundant reserves, and improved unconventional and offshore recovery technology. Increased natural gas production is expected to come mainly from onshore sources, although offshore Gulf of Mexico production also is forecast to grow significantly. In August 2001, for instance, ExxonMobil began production at its $330 million Mica natural gas project in the deepwater Gulf of Mexico. Alaska's North Slope fields also represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas reserves. Alaska's Governor Tony Knowles has stated that he supports a $17.2 billion natural gas pipeline running from the North Slope along the Alaska Highway into Alberta and on to markets in the U.S. Midwest (another option would be to route the pipeline via the MacKenzie Delta in northern Canada). Increased natural gas production likely will come mainly from lower 48 sources, with increased use of cost-saving technologies expected to result in continuing large natural gas finds, including in the deep waters of the Gulf of Mexico but also in conventional onshore fields. Currently, top natural-gas-producing states (in descending order) include Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Colorado, Kansas, Alaska, California, and Alabama.

Natural Gas Demand

From 1990 through 2001, natural gas consumption in the United States increased by about 14%, and this growth is likely to continue in the future. Greater use of natural gas as an industrial and electricity generating fuel can be attributed, in part, to its relatively clean-burning qualities in comparison with other fossil fuels. Lower costs resulting from greater competition and deregulation in the natural gas industry and an expanding transmission and distribution network have also helped expand its acceptance and use. In 2001, natural gas consumption fell by over 1.1 Tcf, after a 0.9 Tcf increase in 2000. During 2001, natural gas consumption by electric utilities fell sharply, to 2,675 billion cubic feet (Bcf), down 368 Bcf from 2000. Natural gas is consumed in the United States mainly in the industrial (42%), residential (22%), commercial (15%), and electric utility (13%) sectors (note: EIA generally places consumption of natural gas for power generation by nonutilities, including natural gas used for industrial cogeneration, in the "industrial" category). For the first three months of 2002, natural gas demand is down 5% from the same period the previous year.

U.S. natural gas consumption and imports, largely from Canada (and to a far lesser extent from liquefied natural gas -- LNG, with Mexico a small net importer of natural gas from the United States), are expected to expand substantially in coming decades, with the fastest volumetric growth resulting from additional natural-gas-fired electric power plants. In particular, new combined-cycle facilities furnished with more efficient natural gas turbines will help lower the cost of natural-gas-generated electricity to levels competitive with coal-fired plants. Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure -- $1.5 trillion over the next 15 years according to the National Petroleum Council. The largest natural gas pipeline project currently under construction is the $1.2 billion Gulf Stream pipeline, which will run 564 miles from Alabama to Florida. Mexico could potentially become a significant natural gas exporter to the United States in the long term. One U.S.-Mexican natural gas pipeline proposal currently on the table is the $230-million, 212-mile North Baja line connecting southeastern California and Tijuana, Mexico. Companies involved in this project include Sempra Energy, PG&E, and Mexico's Proxima Gas. The project is slated to come online in January 2003, but is currently awaiting approval by the U.S. Federal Energy Regulatory Commission (FERC).

Domestic and Import Pipelines

On November 1, 1993, FERC issued Order No. 636, which decoupled the various stages of the natural gas industry between wellhead and end-user. This order has led to significant restructuring of the interstate natural gas pipeline industry, including moves towards unbundled services, diversification into other energy sectors, and development of mega-pipeline systems.

During the past decade, interstate natural gas pipeline capacity has increased substantially. From January 1996 through August 1998 alone, at least 78 projects were completed adding approximately 11.7 billion cubic feet per day of capacity, and much more will be needed in coming years. Recently completed pipelines include the Pony Express project and the Trailblazer system expansion, providing access from the Wyoming and Montana production regions. Also, the Transwestern and El Paso natural gas pipeline expansions have increased capacity from New Mexico's San Juan Basin.

On December 1, 2000, the $2.9-billion, 1.3-Bcf/day Alliance Pipeline from western Canada (Fort St. John, British Columbia) to the Chicago area entered service. Another pipeline, the Independence Pipeline ($678 million), has been delayed until November 2002, but received FERC approval in July 2000. Columbia Gas System's Millennium project ($700 million), which would connect Canadian natural gas sources to New York and Pennsylvania, remains in the regulatory approval process. In February 2000, FERC issued Order 637, the goal of which is to build on Order 636 and to further deregulate the U.S. natural gas industry. The order calls for price liberalization for short-term resale of pipeline capacity and allowance of seasonal rate differentials.

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. The U.S. and Canadian natural gas grids are highly interconnected and Canadian natural gas has become an increasingly important component of the total natural gas supply for the United States. This is especially true for certain U.S. regions such as the Northeast, Midwest, and Pacific, which depend on Canadian natural gas for significant amounts of their supply. Overall, the United States received about 3.8 Tcf of natural gas (net) from Canada in 2001. Mexico is a small net importer of natural gas from the United States.

The most significant recent expansion of natural gas pipeline capacity from western Canada to the United States is the Northern Border system through Montana into the Midwest. Expansion of the TransCanada pipeline will add another 164 Bcf to these imports, while the new Alliance pipeline from western Canada to Chicago will add as much as 730 Bcf (although not immediately; for a while there will be spare pipeline capacity as production capacity ramps up). This trend is expected to continue as Canadian production expands rapidly in the western provinces of British Columbia and Alberta and is developed off the east coast of Nova Scotia. Consequently, more pipeline projects are expected to be built to gain greater access to these Canadian supplies, including proposed expansion of the NOVA system in Alberta, Canada, by up to 2.3 Bcf per day. This in turn will link with the TransCanada Pipeline system expansion and its connections with existing and new U.S. pipelines feeding into the expanding markets in the Midwest and Northeast. In addition, the Maritimes & Northeast Pipeline running from Sable Island to New England, began operations in early 2000.

On October 12, 2001, the U.S. Coast Guard lifted the ban on liquefied natural gas (LNG) tankers from Boston harbor. The ban, in effect since September 26 (two weeks after the terrorist attacks in New York and Washington, DC), was established in response to security and safety concerns about the ships that bring LNG to the import facility of Distrigas of Massachusetts (a Division of Tractebel, Inc.). The decision enabled the reopening of the Distrigas facility in Everett, Massachusetts, which received 45 shipments containing 99 Bcf of natural gas in 2000, mostly from Trinidad, accounting for 44% of total LNG imports into the United States that year. LNG is an integral part of natural gas supplies for New England. This is particularly true during the winter season, when LNG represents around 30% of local distribution company (LDC) deliveries to consumers. The Distrigas facility is one of three currently active LNG facilities in the United States. The other two active facilities are located in Lake Charles, Louisiana, and the recently reopened facility in Elba Island, Georgia. An additional LNG facility, in Cove Point, Maryland, is scheduled to reopen in 2002. There is growing interest in LNG to supply natural gas for electric power generation and provide supply flexibility. EIA expects that LNG imports to the United States will increase at an average 8.6% annual rate to 830 Bcf by 2020.

Natural Gas Mergers, Acquisitions, Bankruptcies

As with oil, a number of major natural gas market participants are engaging in various forms of corporate combinations, such as mergers, acquisitions, and strategic alliances. The value of mergers and acquisitions within the natural gas industry quadrupled from $10.4 billion in 1990 to $39 billion in 1997. This increase parallels an enormous surge in corporate combinations (mergers, acquisitions, joint ventures and strategic alliances) across the energy sector. In August 2001, Devon Energy announced the acquisition of Mitchell Energy for $3.1 billion, forming the second largest independent natural gas producing company in the United States, behind Anadarko Petroleum Corp. In late January 2001, El Paso Energy completed its $24-billion merger with Coastal, creating the fourth-largest U.S. energy company by market capitalization (after BP, Texaco-Chevron, and Enron). The October 1999 merger between El Paso Energy Corporation and Sonat had created the largest transporter of natural gas in the country.

On December 2, 2001, Enron, formerly the world's largest electricity and natural gas trading company, filed for Chapter 11 bankruptcy in the Southern District of New York for 14 affiliated entities, including Enron, Enron North America, Enron Energy Services, Enron Transportation Services, Enron Broadband Services, and Enron Metals & Commodity Corporation. Enron had been the seventh-largest publicly-traded energy company in the world. Also in early December 2001, Enron filed a $10 billion lawsuit against Dynegy, alleging breach of contract, in connection with Dynegy's November 28 termination of its proposed merger with Enron. On November 9, 2001, Enron had agreed to an all-stock takeover by former competitor Dynegy. ChevronTexaco, a 27% stakeholder in Dynegy, was to inject $1.5 billion of cash immediately into Enron, and an additional $1 billion into the combined entity. The merged company was to be called Dynegy Inc., and Dynegy executives were to occupy all top positions. On November 28, 2001, however, Dynegy withdrew from the merger deal.

On January 2, 2002, the U.S. Department of Justice confirmed that a criminal probe of Enron has been launched. A task force was formed to investigate whether the former giant energy company defrauded investors by deliberately withholding or falsifying crucial financial information. The U.S. Securities and Exchange Commission has been investigating Enron since October 2001. A number of civil suits already have been filed against Enron.

COAL

The United States produced 1,121 million short tons (Mmst) of coal in 2001, consumed 1,081 Mmst and exported (net) 49 Mmst. Wyoming is by far the leading U.S. coal-producing state (with 33% of the U.S. total), followed by West Virginia (14%) and Kentucky (12%). Appalachia accounted for 38% of total U.S. production in 2001, mainly from underground mines. Nearly all remaining U.S. coal production came from states west of the Mississippi River, overwhelmingly from surface mines. Around three-fifths of U.S. coal production is bituminous, one-third subbituminous, and about one-tenth lignite (brown coal). Around 80,000 miners work in the $20 billion U.S. coal industry, down from a peak of

700,000 in 1923, when U.S. coal production was half what it is today. Major U.S. coal companies include Peabody Energy (the largest in terms of production), Arch Coal (the second largest coal producer); and Kennecott Energy.

During 2001, coal production increased in all regions of the United States, particularly the West. Low-sulfur western coal production surpassed relatively higher-cost, higher-sulfur, Appalachian coal for the first time in 1998, following strong increases since 1994, prompted largely by Phase 1 of the Clean Air Act Amendments of 1990 (CAAA). CAAA originally took effect during 1995, and required lower sulfur emissions from coal combustion. In response, Wyoming increased its coal production sharply, particularly low-sulfur, low-ash (and low cost) coal from the Powder River Basin, where coal is strip-mined. Output growth from Appalachia in 1996 was largely a result of strong demand by eastern electric utilities, a decline in nuclear and natural-gas-fired generation in the East, and a rise in exports. A proposal to ship Western coal to power plants in the eastern and midwestern United States via a new, $1.4 billion rail line currently is under consideration by Federal regulators.

The electric power sector (utilities and nonutilities) accounts for the vast majority (around 90%) of U.S. coal consumption, with independent power producers (IPPs) and manufacturing taking nearly all the rest. This pattern is expected to continue through 2020 at least, with coal maintaining a fuel cost advantage over oil and natural gas, and coal demand reaching 1,365 Mmst. As sulfur dioxide emissions standards are tightened (in 2000, for instance, Phase 2 of CAAA took effect), the share of low-sulfur coal in the U.S. coal consumption mix is expected to increase. In 1999, low and medium-sulfur coals had approximately the same share of the U.S. coal market, with high-sulfur coal far behind.

U.S. coal exports have fallen precipitously since 1995 due mainly to lower world coal prices and increased competition from other coal-producing nations (i.e., Australia, South Africa, China, Venezuela, Colombia), plus natural gas -- especially in Europe. In 2001, total U.S. coal exports dropped to the lowest level since 1978, largely due to 1) a strong U.S. dollar, which gave an edge to other coal-exporting countries; and 2) the tight supply market in the United States, which resulted in increased spot prices of coal, influencing some producers to shift their output to the domestic market. Metallurgical coal exports experienced the greatest decline in 2001, accounting for 75% of the total decline. Export markets for metallurgical coal have been declining over the past few years because of the expansion of new steel-making technologies requiring less high-grade coking coal. Consequently many U.S. metallurgical coal operations have closed, and increased amounts of metallurgical coal have been sold into the domestic utility steam coal market. The U.S. coal industry is expected to continue to face strong competition from other coal-exporting countries, with limited or negative growth in import demand in Europe and the Americas. Given this, it is likely that the U.S. share of world coal exports will decline in coming years.

Meanwhile, U.S. coal imports, although still representing an extremely small part of total U.S. coal consumption (less than 2%), increased dramatically in 2001. Total coal imports were 19.8 million short tons, an increase of 58% from the previous year. The rise in imports is attributable to both the heightened demand for low-sulfur coal to meet the stricter sulfur emission requirements of Phase II of the CAAA, and to the the tight coal supply market that existed for most of 2001.

ELECTRICITY

In 2001, the United States generated 3,779 billion kilowatthours (Kwh) of electricity, including 2,661 billion Kwh at electric utilities plus an additional 1,116 billion Kwh at nonutility producers. For utilities, coal-fired plants accounted for 60% of generation, nuclear 20%, natural gas 10%, hydroelectricity 7%, oil 3%, geothermal and "other" 0.1%. For non-utilities, natural gas plants accounted for around 32% of generation, coal 32%, nuclear 21%, "geothermal and other" (including geothermal, wind, solar, wood and waste) about 8%, oil 5%, hydroelectric at 2%, and "other gaseous fuels" (including refinery still gas and liquefied petroleum gases) 1%. In general, natural gas-fired power plants have been gaining share the past few years. Coal-fired power plants generally have been less attractive than natural-gas-fired plants due to relatively high capital costs, longer construction periods, and lower efficiencies than natural gas combined-cycle plants.

On a national level, the price of electricity sold by utilities during 2001 averaged 7.16 cents per Kwh, up from 6.68 cents per Kwh during 2000, with higher natural gas input prices largely responsible. Electricity prices in the United States fell every year between 1993 and 1999, but this trend reversed in 2000 and 2001.

As of January 1, 1999, U.S. nameplate generating capacity at electric utilities was 639 gigawatts (GW). Based on primary energy source, coal-fired capacity represented 43% of the nation's existing electric generating capacity in 1999. Natural-gas-fired capacity accounted for 19%; nuclear for 15%; hydroelectricity for 12%; petroleum for 8%; and "renewables" (geothermal, solar, wind) for about 1%. The amount and geographical distribution of capacity by energy source is a function of availability and price of fuels and/or regulations. Capacity by energy source generally shows a geographical pattern such as: significant petroleum-fired capacity in the East, hydroelectric in the West, and natural-gas-fired capacity in the Coastal South.

This summer, total electricity demand is expected to be level with last summer's demand. Cooling degree-days are expected to be somewhat lower than last year, assuming normal weather for May through September. Although the economy is assumed to be growing through the summer months, year-over-year increases in industrial output are not expected to show up until the third quarter of this year.

Over the long term, U.S. power demand is increasing rapidly, with EIA forecasting 1.8% average annual growth in electricity sales through 2020. This increase will require a significant addition in generating capacity, with EIA forecasting that 1,300 new power plants will be needed over the next 20 years. Whether these plants are natural-gas-fired, coal-fired, "renewable," or nuclear depends on a mix of factors, including economics and government policy, but if recent trends continue, it is likely that the vast majority of new plants will be natural-gas-fired, with oil accounting for less than 1% of power generation by 2020.

The changing structure of the U.S. electric power industry has resulted in many electric utilities restructuring their companies and selling their generating assets, primarily to nonutility companies. During 1999, approximately 55,070 MW of capacity was sold to nonutility companies. On March 31, 1998, retail customers of investor-owned utilities in California (approximately three-fourths of the state's customers) were allowed direct access to an alternative energy (electricity) service provider. Also during 1998, Massachusetts and Rhode Island opened their retail electricity markets. Meanwhile, legislatures and/or public utility commissions in 18 other states (plus the District of Columbia) also have approved or implemented plans to move toward retail competition (although California's problems have caused many of these states to take a second look. On April 2, 2001, Entergy and the FPL Group called off a proposed $7.6-billion merger which would have created the largest power distribution company in the United States. This follows the collapse in 2000 of a proposed $3.3-billion merger between Connecticut's Northeast Utilities and New York's Consolidated Edison Co.

During much of 2000 and early 2001, California confronted a major power problem, with intermittent "rolling blackouts" and "Stage 3" (the highest level) alerts. Causes of this situation included: 1) sharply increased (11%) power demand in California over the past decade as a result of a surging economy and low power costs to consumers; 2) stagnant supply over the same period; 3) low hydropower output levels in the Northwest due to below-normal rainfall; 4) California's heavy reliance on out-of-state capacity and power imports; 5) high natural gas prices and lingering problems from the August 2000 El Paso natural gas pipeline explosion; 6) significant problems stemming from California's Electric Utility Industry Restructuring Act of 1996; and 7) serious financial problems at utilities (PG&E, SCE). Serious problems, however, were largely avoided during the summer of 2001 due to conservation, a downturn in California's economy (and hence power demand), the addition of power generating capacity, and higher power prices. On September 24, 2001, as required by law, the CPUC effectively put an end to deregulation of retail electricity in California. Although California for the most part avoided power blackouts or other major problems this past summer, financial difficulties continue at utilities like Pacific Gas & Electric (PG&E, in bankruptcy) and Southern California Edison (close to bankruptcy). On October 22, 2001, the US Department of Energy, in partnership with PG&E, announced that it would spend $300 million to upgrade Path 15, a series of power transmission lines connecting northern and southern California. As of early 2002, California had excess power generation and minimal risk of power outages.

In March 2001, the Energy Secretaries of Canada, Mexico, and the United States met to discuss a common energy strategy for the three countries, including integration of the three countries' power grids and creation of a US-Mexican working group to focus on promoting cross-border electricity trade. At present, power trade between Mexico and the United States is severely limited by infrastructure constraints, including inadequate power transmission capability (there are only two cross-border transmission lines: San Diego-Tijuana and El Paso-Matamoros). In January 2001, a small (50-MW), natural-gas-fired power plant in Baja California began exporting power to California. Canada exported about 42.9 bkwh of electricity to the United States in 1999, mostly from Quebec, Ontario, and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Washington state, Minnesota, California, and Oregon. There is considerable reciprocity between the Canadian and U.S. power markets, as the United States also exports smaller volumes of electricity to Canada.

Nuclear

In 2001, U.S. nuclear power generation reached a record 769 billion kWh, or about 20% of total U.S. electricity generation, second only to coal in the U.S. electricity generation mix. Nuclear power's share of U.S. utility electric generating capacity in 2001 was highest in the New England region (69% of utility generation), followed by the Middle Atlantic (37%), the South Atlantic (29%), the Pacific Coast (24%), the East South Central (20%), the West South Central (17%), the West North Central (16%), the East North Central (12%), and the Mountain region (10%). Approximately one-fourth of U.S. nuclear output was provided by just three statest: Illinois, Pennsylvania, and South Carolina. The average capacity factor for all nuclear units nationwide increased from 88.1% in 2000 to 89.7% in 2001, an all-time record high utilization rate. Following the September 11, 2001 terrorist attacks on the United States, security at nuclear power plants around the United States was increased dramatically.

Nuclear power in the United States grew rapidly after 1973, when only 83 billion kWh of nuclear power was produced. As of 2001, nuclear power had grown nine-fold, with 104 licensed nuclear power units generating 769 billion kWh of electricity. This rapid growth in nuclear power generation, however, obscures serious underlying problems in the U.S. nuclear industry. After 1974, many planned units were canceled, and since 1977, there have been no orders for any new nuclear units, and none are currently planned. The 1979 Three Mile Island accident greatly increased concerns about the safety of nuclear power plants in the United States. The regulatory reaction to those concerns contributed to the decline in the number of planned nuclear units. In late March 2000, the Nuclear Regulatory

Commission (NRC), in a positive signal to the U.S. nuclear power industry, granted the first-ever renewal of a nuclear power plant's operating license. The 20-year extension (until 2034 and 2036 for two reactors) went to the 1,700-MW Calvert Cliffs plant in Maryland. As of March 2002, Exelon and Dominion Resources reportedly were looking at sites to build the first new nuclear power plants in the United States in two decades.

After a period of heightened concern for the availability of nuclear generation this summer, the prospect for normal operations appears likely. Upon discovery of corrosion in a major component in a nuclear plant in Ohio, the Nuclear Regulator Commission ordered the submission of safety information on 68 other units, implying the possible need for shutdowns for inspections. It now appears the problem is confined to one unit and the cause is being investigated. The temporary loss of this capacity is offset by increases in capacity at several reactors due to NRC-approved upgrades ranging from 2% to 20% and totaling several hundred megawatts in each year of the projection. Nuclear generation is expected to be up by about 0.6%-0.7% in 2002 and 2003.

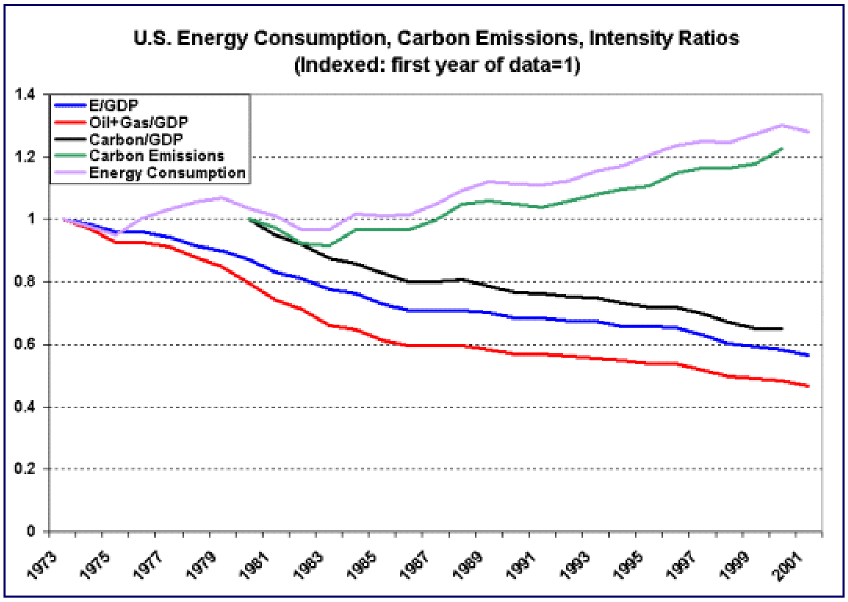
In January 2002, Energy Secretary Spencer Abraham notified Nevada officials that he had formally recommended Yucca Mountain, located 100 miles north of Las Vegas, as the nation's permanent nuclear waste depository. Studies on Yucca Mountain as a possible nuclear power plant waste site have been going on for over two decades, with concerns centering on the dangers of transporting nuclear materials to the site via rail or highway. Nuclear utilities have complained that they are running out of nuclear waste storage capacity at their nuclear plants, with many being forced to resort to "dry cask" storage of spent fuel assemblies after water-storage pools reached capacity.

Hydroelectricity/Other "Renewables"

The United States consumed 6.2 quadrillion Btu of renewable energy in 2001, about 6% of total domestic gross energy demand, with the largest component used for electricity production. Hydropower made up around 39% of total U.S. renewable consumption in 2001, with biofuels (including wood and waste), solar, wind, and geothermal making up most of the remainder. In 2001, total hydropower generation was down to lows not seen since 1966. In early 2002, the U.S. Northeast experienced a serious drought, calling into question the adequacy of hydroelectricity supplies during the upcoming summer season. As of May 1, however, the drought appeared to have eased somewhat following heavy rains in much of the region. Overall, total hydro generation is expected to rise by 22% in 2002 if normal precipitation materializes in the Pacific Northwest, the main region affected.

Wind, solar, biomass, and geothermal power, although growing, still supply only a tiny fraction of U.S. energy needs. In January 2000, however, the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) released a report which said that the domestic photovoltaic (PV) industry could provide up to 15% of "new U.S. peak electricity capacity expected to be required in 2020." Wind, geothermal, and biomass energy sources also have significant potential in the United States.

In 2001, 1,694 MW of wind power was installed in the United States, more than twice the previous record of 732 MW installed in 1999, according to the American Wind Energy Association (AWEA). This increase, driven in part by a federal wind production tax credit, boosted total U.S. installed wind generating capacity to 4,258 MW, with wind turbines now located in 26 states. The first U.S. offshore windmill park reportedly is scheduled to be built off the Cape Cod coast, with 170 windmills to be installed beginning in 2004. The project could power more than 200,000 homes in Cape Cod.



ENVIRONMENT

The United States, with the world's largest economy, is also the world's largest single source of anthropogenic (human-caused) greenhouse gas emissions. Quantitatively, the most important anthropogenic greenhouse gas emission is carbon dioxide, which is released into the atmosphere when fossil fuels (i.e., oil, coal, natural gas) are burned. Current projections indicate that U.S. emissions of carbon (mainly in the form of carbon dioxide) will reach 1,694 million metric tons in 2005, an increase of 357 million metric tons from the 1,337 million metric tons emitted in 1990, and around one-fourth of total world energy-related carbon emissions. At the December 1997 global warming summit in Kyoto, Japan, the U.S. delegation agreed to reduce U.S. carbon emissions 7% from 1990 levels by 2008-2012. Given current EIA projections, it is unlikely that this goal will be met. In February 2002, the Bush Administration released its proposed alternative to the Kyoto Treaty, calling for significant reductions in emissions of various pollutants (mercury, nitrogen oxide, sulfur dioxide). The program, known as the "Clear Skies Initiative," would utilize a "cap and trade" system which would allow companies to trade emissions credits. In addition, the Bush Administration envisions reductions in U.S. "greenhouse gas intensity" -- the amount of greenhouse gases emitted per dollar of GDP -- by 18% over 10 years. As the graph here shows, U.S. carbon emissions per dollar of GDP have been declining steadily since at least 1980.

U.S. energy-related carbon emissions have been increasing in recent years for three main reasons. First, the U.S. economy experienced strong economic growth during the 1990s, which in combination with generally low oil prices for most of the period (until recently), caused energy consumption to increase. Second, the energy "efficiency gains" of the 1980s, which were prompted largely by the oil price spikes of the 1970s, have been leveling off for several years now, particularly since the 1985/86 oil price collapse. Sales of sport-utility vehicles, minivans, and small trucks, for instance, all of which are less fuel efficient than small cars, have increased sharply in recent years. Third, nuclear power generation (which emits no carbon), has now stagnated and is expected to decline after expanding rapidly during the 1970s and 1980s. Hydroelectricity, the other major non-fossil energy source in the United States, also has not been growing.

Since taking office on January 20, 2001, the Bush Administration has taken a series of actions related to energy and the environment. On February 28, 2001, EPA Administrator Christine Todd Whitman directed her agency to move ahead with a rule issued by President Clinton that will require U.S. refiners to reduce sulfur in diesel fuel from 500 parts per million currently, to 15 parts per million by 2006. On March 13, 2001, President Bush declared that his administration would not seek to regulate power plants' emissions of carbon dioxide, citing an EIA study that regulating these emissions could result in higher electricity prices. On March 27, the Bush administration declared that the United States had "no interest" in implementing or ratifying the Kyoto treaty, saying it would be too harmful to the U.S. economy, and that it would pursue other ways of addressing the climate change issue. On April 10, the EPA asked the U.S. Court of Appeals in Washington, DC to uphold a Clinton administration plan to regulate mercury pollution from coal-fired power plants, beginning in 2004. On April 12, the White House affirmed Clinton administration-approved energy efficiency standards for washing machines and water heaters. Under these standards, clothes washers would become 22% more efficient by 2004 and 35% more by 2007. The next day (April 13), the Department of Energy announced that it would require air conditioners to be 20% more energy efficient by 2006. The Clinton administration had mandated a 30% energy efficiency increase for air conditioners. In January 2002, Energy Secretary Spencer Abraham announced an initiative, known as "Freedom CAR," to help automakers produce fuel-cell-powered electric vehicles.

COUNTRY OVERVIEW
President: George W. Bush (since January 20, 2001)
Legislative Branch: Bicameral Congress (Senate, House of Representatives)
Judicial Branch: Supreme Court
Independence: July 4, 1776
Population (July 2001E): 278 million
Location/Size: North America, between Canada and Mexico/9,629,091 sq. km (3,717,792 sq. miles)., the third largest country in the world, behind Russia and Canada
Major Cities: Washington, DC (capital), New York, Los Angeles, Chicago, Houston, Miami, Philadelphia, etc.
Languages: English, Spanish (spoken by a sizable minority)
Ethnic Groups (8/1/2000): White (82.2%), Black (12.8%), Asian (4.1%), Native American (0.9%). Note: Hispanics, who can be of any race, made up 11.8% of the U.S. population as of 8/1/2000.
Religions (1997): Protestant (58%), Roman Catholic (26%), Jewish (2%), other (6%), none (8%)
Defense (8/98): Army, 479,400; Navy, 380,600; Air Force, 370,300; Marine Corps, 171,300 (the United States also has nearly 1.35 million reservists)

ECONOMIC OVERVIEW
Currency: Dollar ($)
Exchange Rates, per Dollar (10/25/2001): British Pound (0.6992); Canadian Dollar (1.58); Euro (1.1259); French Franc (7.3201), German Mark (2.1825); Japanese Yen (122.68)
Gross Domestic Product (GDP) (2001E): $10.3 trillion
Real GDP Growth Rate: (2001E): 1.2% **(2002F):** 1.6% **(2003F):** 3.8%
Inflation Rate (GDP implicit price deflator) (2001E): 2.2% **(2002F):** 1.5% **(2003F):** 2.1%
Unemployment Rate (2000E): 4.2% **(2001E):** 4.8%
Current Account Balance (2000E): -$435.4 billion **(2001E):** -$453 billion
Merchandise Exports (2001E): $1,081 billion **(2002F):** $1,021 billion
Merchandise Imports (2001E): $1,494 billion **(2002F):** $1,458 billion
Merchandise Trade Balance (2001E): -$413 billion **(2002F):** -$437 billion
Major Exports (1999): Capital goods excluding automobiles ($312 billion), industrial supplies ($142 billion), consumer goods excluding autos ($81 billion), motor vehicles and parts ($76 billion), services ($291 billion)
Major Imports (1999): Capital goods excluding autos ($297 billion), consumer goods excluding autos ($240 billion), motor vehicles and parts ($179 billion), industrial supplies excluding oil ($149 billion), petroleum and products ($68 billion), services ($196 billion)
Major Trading Partners: Canada, Japan, European Union, Mexico

ENERGY OVERVIEW
Secretary of Energy: Spencer Abraham (as of January 20, 2001)

Proven Oil Reserves (1/1/02E): 22.0 billion barrels
Oil Production (2001E): 8.1 million barrels per day (bbl/d), of which 5.9 million bbl/d is crude oil (NOTE: Including "refinery gain," US oil production in 2001 is estimated at 9.0 million bbl/d)
Oil Consumption (2001E): 19.6 million bbl/d
Net Oil Imports (2001E): 10.6 million bbl/d
Crude Oil Imports from the Persian Gulf (2001E): 2.6 million bbl/d (around 29% of total U.S. crude oil imports)
Value of Oil Imports (2001E): $97.0 billion (down from $119.3 billion in 2000)
Crude Oil Refining Capacity (2002E): 16.5 million bbl/d (91% utilization rate as of 10/12/01)
Oil Stocks (8/01E): 1.55 billion barrels (including about 545 million barrels in the U.S. Strategic Petroleum Reserve)
Oil Wells Drilled (2001E): 7,949 (up from 7,358 in 2000)
Operating Oil and Natural Gas Rotary Rigs (2/02E): 825 (679 for natural gas and 144 for oil)
Natural Gas Reserves (1/1/02E): 177 trillion cubic feet (Tcf)
Dry Natural Gas Production (2001E): 19.1 Tcf
Natural Gas Consumption (2001E): 22.7 Tcf
Net Natural Gas Imports (2001E): 3.5 Tcf (over 90% from Canada)
Natural Gas Wells Drilled (2001E): 21,224 (up from 15,598 in 2000)
Recoverable Coal Reserves (12/31/98): 275.1 billion short tons (54% lignite and subbituminous; 46% anthracite and bituminous)
Coal Production (2001E): 1,121 million short tons (Mmst)
Coal Consumption (2001E): 1,081 Mmst
Gross Coal Exports (2001E): 49 Mmst
Value of Coal Exports (1999E): $2.5 billion
Coal Stocks (12/01E): 171.1 Mmst
Electric Utility Generation Capacity (1/1/99E): 639 gigawatts (coal 43%, natural gas 19%, nuclear 15%, hydroelectric and other renewables 13%, and petroleum 8%)
Electric Net Generation by Utilities (2001E): 2,661 billion kilowatthours (of which coal-fired 60%, nuclear 20%, natural gas 10%, hydroelectricity 7%, oil 3%, geothermal and "other" 0.1%)
Non-utility Power Production (2001E): 1,116 billion kilowatthours (of which natural gas-fired 32%, coal 32%, nuclear 21%, "geothermal and other" 8%, oil 4%, hydroelectric 2%, and "other gaseous fuels" 2%)
Total Electricity Generation (2001E): 3,779 billion kilowatthours

ENVIRONMENTAL OVERVIEW
Administrator of the U.S. Environmental Protection Agency: Christine Todd Whitman
Total Energy Consumption (2001E): 97.0 quadrillion Btu (25% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 1,583 million metric tons of carbon (about 25% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 348.9 million Btu
Per Capita Carbon Emissions (2000E): 5.7 metric tons of carbon
Energy Intensity (2001E): 10,390 Btu/$1996
Carbon Intensity (2000E): 0.17 metric tons of carbon/thousand $1996
Sectoral Share of Energy Consumption (2001E): Industrial (35%), Transportation (26%), Residential (21%), Commercial (18%)
Sectoral Share of Carbon Emissions (1998E): Industrial (32.6%), Transportation (32.0%), Residential (19.4%), Commercial (16.0%)
Fuel Share of Energy Consumption (2001E): Oil (39%), Natural Gas (23%), Coal (23%), Renewables (6%)
Fuel Share of Carbon Emissions (2000E): Oil (42%), Coal (37%), Natural Gas (21%)

Renewable Energy Consumption (2001E): 6,173 trillion Btu (about 39% of which was conventional hydroelectric power)
Number of People per Motor Vehicle (2000E): 1.3
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified October 15th, 1992). Under the negotiated Kyoto Protocol (signed on November 12th, 1998 - not yet ratified), the United States agreed to reduce greenhouse gases 7% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Air pollution resulting in acid rain in both the US and Canada; the US is the largest single emitter of carbon dioxide from the burning of fossil fuels; water pollution from runoff of pesticides and fertilizers; very limited natural fresh water resources in much of the western part of the country require careful management; desertification.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Antarctic-Environmental Protocol, Antarctic Treaty, Climate Change, Endangered Species, Environmental Modification, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified, Air Pollution-Persistent Organic Pollutants, Air Pollution-Volatile Organic Compounds, Biodiversity, Desertification, Hazardous Wastes.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

ENERGY INDUSTRY
Major U.S. Oil Companies: ExxonMobil, Texaco, Chevron, BP, Shell, USX, Phillips, Conoco
Major U.S. Coal Companies: Peabody Holding Co., Inc.; Cyprus AMAX Minerals Co.; Consol Energy Inc.; Kennecott Energy Co.; Zeigler Coal Holding Co.
Oil Pipelines (2001E): Around 2 million miles **Natural Gas Pipelines (2000E):** 278,000 miles
Major Ports: Baltimore, Chicago, Hampton Roads, Houston, Los Angeles, New Orleans, New York, Philadelphia

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Sources for this report include: Associated Press; Christian Science Monitor; Dallas Morning News; Dow Jones; DRI/WEFA; EIU Viewswire; Energy Daily; Financial Times; Financial Times Energy Newsletters; Gas Daily; Houston Chronicle; Los Angeles Times; Megawatt Daily; New York Times; PR Newswire; Reuters; U.S. Energy Information Administration (numerous publications -- see links); Washington Post; World Markets Online 2001).

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July 2002

Caspian Sea Region: Reserves and Pipelines Tables

Table 1. Caspian Sea Region Oil and Natural Gas Reserves

Country	Proven* Oil Reserves	Possible** Oil Reserves	Total Oil Reserves	Proven* Natural Gas Reserves	Possible** Natural Gas Reserves	Total Natural Gas Reserves
Azerbaijan	1.2 BBL	32 BBL	33.2 BBL	4.4 Tcf	35 Tcf	39.4 Tcf
Iran***	0.1 BBL	15 BBL	15.1 BBL	0 Tcf	11 Tcf	11 Tcf
Kazakhstan	5.4 BBL	92 BBL	97.4 BBL	65 Tcf	88 Tcf`	153 Tcf
Russia***	2.7 BBL	14 BBL	16.7 BBL	N/A	N/A	N/A
Turkmenistan	0.6 BBL	80 BBL	80.6 BBL	101 Tcf	159 Tcf	260 Tcf
Total	**10 BBL**	**233 BBL**	**243 BBL**	**170.4 Tcf**	**293 Tcf**	**463.4 Tcf**

Sources: Oil and Gas Journal, Energy Information Administration

* proven reserves are defined as oil and natural gas deposits that are considered 90% probable
** possible reserves are defined as oil and natural gas deposits that are considered 50% probable
*** only the regions near the Caspian are included

BBL = billion barrels, Tcf = trillion cubic feet

Table 2. Caspian Sea Region Oil Production and Exports

(thousand barrels per day)

Country	Production (1990)	Est. Production (2001)	Possible Production (2010)	Net Exports (1990)	Est. Net Exports (2001)	Possible Net Exports (2010)
Azerbaijan	259	311.2	1,200	77	175.2	1,000
Kazakhstan	602	811	2,000	109	631	1,700
Iran*	0	0	0	0	0	0
Russia**	144	11	300	0	7	300
Turkmenistan	125	159	200	69	107	150
Total	**1,130**	**1,292.2**	**3,700**	**255**	**920.2**	**3,150**

Source: Energy Information Administration

* only the regions near the Caspian are included
** includes Astrakhan, Dagestan, and the North Caucasus region bordering the Caspian Sea

Table 3. Caspian Sea Region Natural Gas Production and Exports

(billion cubic feet per year)

Country	Production (1990)	Est. Production (2000)	Possible Production (2010)	Net Exports (1990)	Est. Net Exports (2000)	Possible Net Exports (2010)
Azerbaijan	350	200	1,100	-272	0	500
Kazakhstan	251	314.3	1,100	-257	-176.6	350
Iran*	0	0	0	0	0	0
Russia**	219	30	N/A	N/A	N/A	N/A
Turkmenistan	3,100	1,642	3,900	2,539	1,381	3,300
Total	**3,920**	**2,072**	**6,100**	**2,010**	**1,204.4**	**4,150**

Source: Energy Information Administration

* only the regions near the Caspian are included
** includes Astrakhan, Dagestan, and the North Caucasus region bordering the Caspian Sea

Table 4. Oil Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Crude Capacity	Length	Estimated Cost/Investment	Status
Atyrau-Samara Pipeline	Atyrau (Kazakhstan) to Samara (Russia), linking to Russian pipeline system	Recently increased to 310,000 bbl/d	432 miles	Increase in capacity cost approximately $37.5 million	Existing pipeline recently upgraded by adding pumping and heating stations to increase capacity.
Baku-Ceyhan ("Main Export Pipeline")	Baku (Azerbaijan) via Tbilisi (Georgia) to Ceyhan (Turkey), terminating at the Ceyhan Mediterranean Sea port	Planned: 1 million bbl/d	Approximately 1,038 miles	$2.9 billion	One-year detailed engineering study completed in June 2002. Construction on Turkish section of pipeline began in June 2002. Completion of entire pipeline targeted for 2004, exports by Feb. 2005.
Baku-Supsa Pipeline (AIOC "Early Oil" Western Route)	Baku to Supsa (Georgia), terminating at Supsa Black Sea port	Recently upgraded from 115,000 to 145,000 bbl/d; proposed upgrades to between 300,000 bbl/d to 600,000 bbl/d	515 miles	$600 million	Exports began in April 1999; approximately 115,000 bbl/d exported via this route in 2001.
Baku-Novorossiisk Pipeline (Northern Route)	Baku via Chechnya (Russia) to Novorossiisk (Russia), terminating at Novorossiisk Black Sea oil terminal	100,000 bbl/d capacity; possible upgrade to 300,000 bbl/d	868 miles; 90 miles are in Chechnya	$600 million to upgrade to 300,000 bbl/d	Exports began late 1997; exports in 2001 averaged 50,000 bbl/d.

Baku-Novorossiisk Pipeline (Chechnya bypass, with link to Makhachkala)	Baku via Dagestan to Tikhoretsk (Russia) and terminating Novorossiisk Black Sea oil terminal	Currently: 120,000 bbl/d (rail and pipeline: 160,000 bbl/d); Planned: 360,000 bbl/d (by 2005)	204 miles	$140 million	Completed April 2000. Eleven-mile spur connects bypass with Russia's Caspian Sea port of Makhachkala.
Caspian Pipeline Consortium (CPC) Pipeline	Tengiz oil field (Kazakhstan) to Novorossiisk Black Sea oil terminal	Currently: 565,000-bbl/d; Planned: 1.34-million bbl/d (by 2015)	990 miles	$2.5 billion for Phase 1 capacity; $4.2 billion total when completed	First tanker loaded in Novorossiisk (10/01); exports rising to 400,000 bbl/d by end-2002
Central Asia Oil Pipeline	Kazakhstan via Turkmenistan and Afghanistan to Gwadar (Pakistan)	Proposed 1 million bbl/d	1,040 miles	$2.5 billion	Memorandum of Understanding signed by the countries; project stalled by regional instability and lack of financing.
Iran-Azerbaijan Pipeline	Baku to Tabriz (Iran)	Proposed 200,000 bbl/d to 400,000 bbl/d	N/A	$500 million	Proposed by TotalFinaElf.
Iran Oil Swap Pipeline	Neka (Iran) to Tehran (Iran)	175,000 bbl/d, rising to 370,000 bbl/d	208 miles	$400 million to $500 million	Under construction; oil will be delivered to Neka and swapped for an equivalent amount at the Iranian Persian Gulf coast.

Kazakhstan-China Pipeline	Aktyubinsk (Kazakhstan) to Xinjiang (China)	Proposed 400,000 bbl/d to 800,000 bbl/d	1,800 miles	$3 billion to $3.5 billion	Agreement 1997; feasibility study halted in September 1999 because Kazakhstan could not commit sufficient oil flows for the next 10 years.
Kazakhstan-Turkmenistan-Iran Pipeline	Kazakhstan via Turkmenistan to Kharg Island (Iran) on Persian Gulf	Proposed 1million bbl/d	930 miles	$1.2 billion	Feasibility study by TotalFinaElf; proposed completion date by 2005.
Khashuri-Batumi Pipeline	Dubendi (Azerbaijan) via Khashuri (Georgia) to Batumi	Initial 70,000 bbl/d, rising to 140,000 bbl/d-160,000 bbl/d	Rail system from Dubendi to Khashuri, then 105-mile pipeline from Khashuri to Batumi	$70 million for pipeline renovation	ChevronTexaco has canceled plans to rebuild and expand the existing pipeline.
Trans-Caspian (Kazakhstan Twin Pipelines)	Aqtau (western Kazakhstan, on Caspian coast) to Baku; could extend to Ceyhan	N/A	370 miles to Baku	$2 billion to $4 billion (if to Ceyhan)	Feasibility study agreement signed in December 1998 by Royal/Dutch Shell, ChevronTexaco, ExxonMobil, and Kazakhstan; project stalled by lack of Caspian Sea legal agreement.

Table 5. Natural Gas Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Capacity	Length	Estimated Cost/Investment	Status

Baku-Erzurum	Baku (Azerbaijan) via Tbilisi (Georgia) to Erzurum (Turkey), linking with Turkish natural gas pipeline system	Planned 254 Bcf capacity	540 miles	$1 billion (includes up to $500 million to construct new Azeri section)	Financing being arranged, construction originally scheduled to start in summer 2002.
"Centgas" (Central Asia Gas)	Daulatabad (Turkmenistan) via Herat (Afghanistan) to Multan (Pakistan). Could extend to India.	700 Bcf/year	870 miles to Multan (additional 400 miles to India)	$2 billion to Pakistan (additional $500 million to India)	Memorandum of Understanding signed by Turkmenistan, Pakistan, Afghanistan, and Uzbekistan. Presidents of Pakistan, Afghanistan, and Turkmenistan met in May 2002 to discuss reviving this pipeline idea.
Central Asia-Center Pipeline	Turkmenistan and Uzbekistan via Kazakhstan to Saratov (Russia), linking to Russian natural gas pipeline system	3.5 Tcf/year	Existing route	N/A	Operational. Turkmenistan is using this pipeline to export a total of 8.83 Tcf to Ukraine (via Russia) from 2002 to 2006, as well as smaller amounts to Russia.
China Gas Pipeline	Turkmenistan to Xinjiang (China). Could extend to Japan.	1 Tcf/year	4,1,61 miles; more if to Japan	$10 billion to China; more if to Japan	Preliminary feasibility study done by ExxonMobil, Mitsubishi, and CNPC
Trans-Caspian Gas Pipeline (TCGP)	Turkmenbashy (Turkmenistan) via Baku and Tbilisi to Erzurum, linking with Turkish natural gas pipeline system	565 Bcf in first stage, eventually rising to 1.1 Tcf/year	1,020 miles	$2 billion to $3 billion	Project stalled; negotiations between Turkmenistan and Azerbaijan over pipeline volumes restarted in October 2001.

Korpezhe-Kurt-Kui	Korpezhe (Turkmenistan) to Kurt-Kui (Iran)	283-350 Bcf/year; expansion proposed to 459 Bcf/year by 2005	124 miles	$190 million; 2005 expansion: $300 million to $400 million	Operational since December 1997.

Table 6. Bosporus Bypass Oil Export Routes
(for Oil Transiting the Black Sea)

Name/Location	Route	Crude Capacity	Length	Estimated Cost/Investment	Status
Adria-Druzhba Integration	Russian Druzhba export pipeline connected to Adria pipeline (flows reversed) to terminus at Omisalj (Croatia)	100,000 bbl/d in first full year of operation; increasing to 300,000 bbl/d	1,987 miles in total	$20 million to modernize Adria, integrate the pipelines, and reverse existing flows	Yukos expects exports from Omisalj via the integrated pipeline system to start by end-2002.
Albanian Macedonian Bulgarian Oil (AMBO) Pipeline	Burgas (Bulgaria) via Macedonia to Vlore (Albania) on Adriatic coast	750,000 bbl/d (could be expanded to 1-million bbl/d)	560 miles	$850 million to $1.1 billion	Construction delayed, (proposed 2001-2002) as financing is arranged. Completion originally targeted for 2004-2005.
Burgas Alexandropoulis (Trans-Balkan Oil Pipeline)	Burgas to Alexandropoulis (Greece) on the Aegean Sea coast	Proposed 600,000 bbl/d to 800,000 bbl/d	178 miles	$600 million	Initial agreement signed in 1997 between Bulgaria, Greece, and Russia. Project delayed.

Constanta-Trieste Pipeline	Constanta (Romania) via Hungary, Slovenia, and/or Croatia to Trieste (Italy) on the Adriatic Sea coast. Omisalj (Croatia) has also been proposed as a terminus.	660,000 bbl/d	855 miles	$900 million	Feasibility studies completed; financing still to be arranged.
South-East European Line (SEEL)	Constanta via Pancevo (Yugoslavia) and Omisalj to Trieste. Omisalj has also been proposed as a terminus.	660,000 bbl/d	750 miles	$800 million	Feasibility studies completed; financing still to be arranged.
Odesa-Brody Pipeline	Odesa (Ukraine) to Brody (Ukraine), linking to the southern Druzhba pipeline; optional spurs to the northern Druzhba line at Plotsk (Poland) and/or to Gdansk on the Baltic Sea coast.	500,000 bbl/d	400 miles from Odesa to Brody	$750 million for pipeline and Pivdenny terminal	Construction on pipeline completed in August 2001; Pivdenny terminal became operational in December 2001. Ukraine is seeking to sign contracts with Caspian oil exporters to fill the line.

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July 2002

Caspian Sea Region

The Caspian Sea region, including the Sea and the littoral states surrounding it, is important to world energy markets because it holds large reserves of undeveloped oil and natural gas. The Caspian Sea's mineral wealth has resulted in disagreements between the five countries over ownership of the resources, and the region's huge energy potential has sparked fierce competition--between producers as well as consumers--over the final export routes for this oil and natural gas.

Note: Information contained in this report is the best available as of July 2002 and is subject to change.

GENERAL BACKGROUND

The Caspian Sea is located in northwest Asia, landlocked between Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan. Since the breakup of the Soviet Union in 1991, the Caspian Sea--as well as the region surrounding it--has became the focus of much international attention due to its huge oil and natural gas reserves. The Sea, which is 700 miles long, contains six separate identified hydrocarbon basins, although most of its oil and natural gas reserves have not been developed yet. Although the littoral states of the Caspian Sea already are major energy producers, many areas of the Sea and the surrounding area remain unexplored.

The prospect of potentially enormous hydrocarbon reserves is part of the allure of the Caspian Sea region (which is defined here to include Azerbaijan, Kazakhstan, Turkmenistan, and the regions of Iran and Russia that are near the Caspian Sea). The Caspian region contains 10 billion barrels of proven oil reserves (defined as oil and natural gas liquids deposits that are considered 90% probable). In addition, despite a string of disappointing recent drilling results, mostly in Azerbaijan, the region's possible oil reserves (defined as 50% probable) could yield another 233 billion barrels of oil.

Overall, proven natural gas reserves in the Caspian region are estimated at around 170 Tcf. Possible natural gas reserves in the Caspian region are even larger, and could yield another 293 trillion cubic feet (Tcf) of natural gas. Turkmenistan (101 Tcf) and Kazakhstan (65 Tcf) are among the top 20 countries in the world in terms of proven natural gas reserves. Although it is not technically part of the Caspian Sea region, nearby Uzbekistan (66.2 Tcf in proven natural gas reserves) also holds significant natural gas deposits.

Since they became independent in 1991, Azerbaijan, Kazakhstan, and Turkmenistan have sought to develop their national oil and natural gas industries. Although the Soviet Union attempted to exploit each of the republic's energy resources, a lack of investment, deteriorating infrastructure, and out-dated technology resulted in declining rates of production in each of the countries at the time of the Soviet Union's collapse in 1991. Over the last 11 years, however, Azerbaijan and Kazakhstan, in particular, have received large amounts of foreign investment in their oil and natural gas sectors. With additional investment, the application of Western technology, and the development of new export outlets, oil and natural gas production in the Caspian region could grow rapidly.

Caspian Legal Status Unresolved

In order for the Caspian Sea region to realize its full energy potential, however, the littoral states must first agree on the legal status of the Sea. Prior to 1991, only two countries--the Soviet Union and Iran--bordered the Caspian Sea, and the legal status of the Sea was governed by 1921 and 1940 bilateral treaties. With the collapse of the Soviet Union and the emergence of Kazakhstan, Turkmenistan, and Azerbaijan as independent states, ownership and development rights in the Sea have been called into question.

Most of Azerbaijan's oil resources (proven as well as possible reserves) are located offshore, and perhaps 30% to 40% of the total oil resources of Kazakhstan and Turkmenistan are offshore as well. Currently, there is no agreed-upon convention that delineates the littoral states' ownership of the Sea's resources or their development rights. The potential oil and natural gas wealth, along with the corresponding environmental risks of resource development in the Caspian, have heightened the stakes for each country.

As a result, several conflicts have arisen over mutual claims to different regions of the Sea, especially in its southern waters. In July 2001, Iranian military gunboats confronted a British Petroleum (BP) Azeri research vessel exploring the Araz-Alov-Sharg structure, ordering the ship out of waters Iran claims as its own. Azerbaijan, for its part, has objected to Iran's decision to award Royal Dutch/Shell and Lasmo a license to conduct seismic surveys in a region that Azerbaijan considers to fall in its territory. In addition, Turkmenistan and Azerbaijan remain locked in a dispute over the Serdar/Kyapaz field, while Turkmenistan claims that portions of Azerbaijan's Azeri and Chirag fields--which Turkmen officials call Khazar and Osman, respectively--lie within its territorial waters.

Thus, the unresolved status of the Caspian Sea has hindered further development of the Sea's oil and natural gas resources, as well as the construction of potential export pipelines from the region. Negotiations between the littoral states have made slow progress in ironing out differences between the countries: while Russia, Azerbaijan, and Kazakhstan have agreed on dividing the Sea by a "modified median" principle, Iran insists on an equal division of the Sea, and Turkmenistan agrees on the principle of dividing the Sea, but not the method. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status, prompting several states to sign bilateral agreements in an effort to solve the problem.

OIL

Despite the lack of a multilateral agreement on the Sea, several countries are undertaking active exploration and development programs in what is generally considered to be their sector of the Caspian Sea. In particular, Azerbaijan and Kazakhstan have made substantial progress in developing their offshore oil reserves.

Azerbaijan has signed a number of production-sharing agreements--both onshore and offshore--in order to develop its oil and natural gas industries. A significant percentage of Azerbaijan's oil production comes from the shallow-water section of the Gunashli field, located 60 miles off the Azeri coast. Although the country's oil production fell after 1991 to just 180,000 barrels per day (bbl/d) in 1997, Azerbaijan's oil production rebounded to 311,200 bbl/d in 2001 with the help of international investment in its oil sector.

Kazakhstan also has opened its resources to development by foreign companies. International oil projects in Kazakhstan have taken the form of joint ventures, production-sharing agreements, and exploration/field concessions. After Russia, Kazakhstan was the largest oil-producing republic in the Soviet Union, but after independence, Kazakhstan's oil production dropped more than 115,000 bbl/d, to 414,000 bbl/d, in 1995. Boosted by foreign investment in its oil sector, Kazakhstan's oil production has increased steadily since then, with output of 811,000 bbl/d in 2001, most of which came from three large onshore fields (Tengiz, Uzen, and Karachaganak). In addition, preliminary drilling in Kazakhstan's offshore sector of the Caspian has revealed bountiful oil deposits, especially in the Kashagan field, raising hopes that Kazakhstan may become one of the world's largest oil producers.

Overall, oil production in the Caspian Sea region reached approximately 1.3 million bbl/d in 2001. Production in the region is projected to increase severalfold, led by three major projects currently under development in Azerbaijan and Kazakhstan:

- In April 1993, Chevron concluded a historic $20 billion deal with Kazakhstan to create the Tengizchevroil joint venture to develop the Tengiz oil field, estimated to contain recoverable oil reserves of six to nine billion barrels. Tengizchevroil was producing approximately 250,000 bbl/d in June 2002, and the consortium is planning to invest $3 billion over the next three years to boost production capacity at the field now that Caspian Pipeline Consortium's Tengiz-Novorosiisk export pipeline is operational. Given adequate export outlets, the Tengizchevroil joint venture could reach peak production of 750,000 bbl/d by 2010.

- In what was described as "the deal of the century," in September 1994 the Azerbaijan International Operating Company (AIOC) signed an $8 billion, 30-year contract to develop three Caspian Sea fields--Azeri, Chirag, and the deepwater portions of Gunashli--with proven reserves estimated at three to five billion barrels. Almost all of Azerbaijan's production increases since 1997 have come from AIOC, which produced an average of 120,000 bbl/d of oil in the first four months of 2002. In August 2001, AIOC and Azeri government officials signed an agreement to carry out an expansion, with oil production at ACG expected to reach 800,000 bbl/d by the end of the decade. The planned Baku-Ceyhan Main Export Pipeline will be the main vehicle for ACG oil exports.

- Although signed with less fanfare in 1997, the offshore Kashagan block being developed by the Agip Kazakhstan North Caspian Operating Company (Agip KCO, formerly OKIOC) may turn out to be more lucrative than both the Tengiz and the ACG group of deposits combined. Exploration and preliminary drilling in the Kashagan block has produced spectacular results, with analysts hailing the field as the largest oil discovery in the last 30 years. Although Agip KCO released estimates in June 2002 that the Kashagan field holds between seven and nine billion barrels of crude in proven reserves, as well as 38 billion barrels in probable reserves, both Kazakh officials and energy analysts have called that estimate "conservative."

These projects, along with others currently underway, could help boost Caspian Sea region production to around 3.7 million bbl/d by 2010. EIA expects production capacity from the Caspian basin to exceed 6.5 million barrels per day by 2020. Although not "another Middle East," as some analysts believed in the early 1990s, the Caspian Sea region is comparable to the North Sea in its hydrocarbon potential.

NATURAL GAS

Unlike with oil, the Caspian region's natural gas resources were extensively developed during the Soviet era. Caspian Sea region natural gas production, not including major Central Asian natural gas producer Uzbekistan, was 3.9 Tcf in 1990, but the collapse of the Soviet Union led to downturns across the region. After 1991, Caspian region natural gas, mostly from Turkmenistan, became a competitor with Gazprom, the Russian state natural gas company. Since Gazprom owned all the pipelines, and since export routes for Caspian natural gas--such as the Central Asia-Center pipeline--were routed through Russia, Caspian natural gas was squeezed out of the hard currency market.

As a result, Turkmenistan's incentives for increasing its production of natural gas disappeared. The country's output dropped throughout the 1990s, plummeting from 2.02 Tcf in 1992 to just 466 billion cubic feet (Bcf) in 1998, when the country was locked in a pricing dispute with Russia over the export of Turkmen natural gas. With high world natural gas prices and a Turkmen-Russian agreement on Turkmen exports in place, the country's natural gas production rebounded to 788 Bcf in 1999, then skyrocketed to 1.64 Tcf in 2000. Turkmenistan has plans to boost natural gas output substantially over the next decade, contingent on securing adequate export routes, such as the proposed Trans-Caspian Gas Pipeline.

Uzbekistan is the third largest natural gas producer in the Commonwealth of Independent States and one of the top ten natural gas-producing countries in the world. Since becoming independent, Uzbekistan has ramped up its natural gas production nearly 32%, from 1.51 Tcf in 1992 to 1.99 Tcf in 2000. In order to offset declining production at some older fields such as Uchkir and Yangikazen, Uzbekistan is speeding up development at existing fields such as the Kandym and Garbi fields, as well as planning to explore for new reserves. However, since Uzbekistan is landlocked and its natural gas competes with Russian and Turkmen natural gas, Uzbekistan is limited in its ability to export. Instead, Uzbekistan has concentrated on supplying the Central Asian natural gas market, mainly through the Tashkent-Bishkek-Almaty pipeline.

Istiglal drilling rig at Shah Deniz in the Caspian Sea.

Source: Azerbaijan International

With the emphasis on Azerbaijan's oil potential, the country's natural gas sector often has been overlooked. In the past, Azerbaijan has imported natural gas from Russia, Turkmenistan, and Iran to meet domestic needs, but consumption has been on the wane since the collapse of the Soviet Union, and in 2000, Azerbaijan's natural gas consumption and production were roughly equivalent at 200 Bcf. Azerbaijan is continuing to import natural gas, but the 1999 discovery of the Shah Deniz field will soon change that.

The Shah Deniz field, which is thought to be the world's largest natural gas discovery since 1978, is estimated to contain between 25 Tcf and 39 Tcf of possible (not proven) natural gas. Development of the field, which will cost upwards of $2.5 billion including related infrastructure, should produce the first natural gas by 2004, making Azerbaijan a significant net natural gas exporter. Already, Azerbaijan has secured an agreement with Turkey to export Azeri natural gas via a planned Baku-Erzurum pipeline.

As investment continues to pour into the Kazakh natural gas sector, the country's natural gas production is set to increase dramatically. In August 2001, the Kazakh Ministry for Energy and Mineral Resources approved a 15-year strategy for developing the country's natural gas sector that would increase natural gas production fivefold. According to the strategy, which the Kazakh government approved, Kazakhstan is aiming to increase its natural gas production to 1.2 Tcf by 2005, to 1.66 Tcf by 2010, and to 1.84 Tcf by 2015. Key to this strategy is the development of natural gas reserves at Kashagan, Karachaganak, and Tengiz. Provided that the necessary infrastructure is built, Kazakhstan soon could become a major natural gas exporter as well.

Overall, natural gas production in the Caspian Sea region reached nearly 2.1 Tcf in 2000. Projects currently underway could help boost Caspian Sea region natural gas production to over 6 Tcf by 2010, and the enactment of laws barring the flaring of associated natural gas may increase the region's total production. In 1999, Azerbaijan enacted a law requiring that each oil production project in the country include a plan to develop its natural gas potential, while Kazakhstan is requiring Agip KCO to capture and use all the associated natural gas from the Kashagan block. Previously, natural gas had been flared off in both countries instead of being piped to consumers because of a lack of a developed infrastructure to deliver natural gas from offshore fields.

EXPORT ISSUES

As increasing exploration and development in the Caspian Sea region leads to increased production, the countries of the region will have additional oil and natural gas supplies available for export. Already, in 2001, Kazakhstan's net oil exports were 631,000 bbl/d, while Azerbaijan's were 175,200 bbl/d. Overall, Caspian Sea region oil exports in 2001 amounted to about 920,000 bbl/d (of the 1.3 million bbl/d produced). With numerous oil projects in the region slated to boost production in the coming years, the region's net exports could increase to over 3 million bbl/d in 2010, and possibly another 2 million bbl/d on top of that by 2020.

With regards to natural gas, Turkmenistan led the way among Caspian Sea region producers with net exports of 1.38 Tcf in 2000. Overall, Caspian Sea region natural gas exports totaled just 1.2 Tcf in 2000, since both Azerbaijan and Kazakhstan have yet to tap their full natural gas production potential (and Kazakhstan is currently a net natural gas importer). With Azerbaijan's Shah Deniz field in development, along with increased investment to develop infrastructure and markets for the region's natural gas, Caspian natural gas exports could increase by another 2-3 Tcf by 2020.

Existing Export Options

In order to boost oil and natural gas exports from the Caspian Sea region, a number of issues will need to be addressed. During the Soviet era, all of the oil and natural gas pipelines in the Caspian Sea region (aside from those in northern Iran) were designed to link the Soviet Union internally and were routed through Russia.

Prior to 1997, exporters of Caspian region oil had only one major pipeline option available to them, the 240,000-bbl/d Atyrau-Samara pipeline from Kazakhstan to Russia. Smaller amounts of oil were exported by barge and by rail through Russia, as well as by a second, smaller pipeline from Kazakhstan to Russia. In the decade since the collapse of the Soviet Union, several new oil export pipelines, such as the Baku-Novorossiisk, the Tengiz-Novorossiisk, and the Baku-Supsa pipelines, have been constructed, and the Atyrau-Samara pipeline recently was upgraded to increase its capacity to 300,000 bbl/d.

Nevertheless, the Caspian region's relative isolation from world markets, as well as the relative lack of export options, continues to hinder exports outside of the former Soviet republics. Of the 920,000 bbl/d exported from the region in 2001, only about 400,000 was exported to consumers outside of the former

Soviet Union.

Natural gas exports from the Caspian region have been even more limited. All of the export pipelines from the region pass through Russia, requiring Caspian region natural gas exporters to make agreements with Gazprom, the Russian monopoly that owns the pipelines, in order to export their natural gas. Since Gazprom is also a competitor with the Caspian region for hard currency natural gas markets, the company has used its position to negotiate better deals and to limit pipeline access for Caspian region natural gas. Turkmenistan's economy, which is concentrated mainly in oil and natural gas, experienced a huge 25.9% decrease in its gross domestic product (GDP) in 1997 when Gazprom denied Turkmenistan access to its pipeline network over a payment dispute.

Since Gazprom has reserved the hard currency markets of Europe for itself by limiting pipeline access for Caspian region natural gas producers, most exports from the region have remained in the Newly Independent States (NIS). Due to the ongoing transition process to a market economic system in much of the NIS, the majority of these former Soviet republics have been unable to pay existing world prices for natural gas supplies. Thus, in order to export their natural gas at all, the Caspian region's producers have had two options: either sell their natural gas to Russia at below-market prices or pay Gazprom a transit fee, then export those supplies via the Russian pipeline system to ex-Soviet states that cannot pay fully in cash or are tardy with payments for supplies already received.

In 1997, Turkmenistan and Iran completed the $190 million Korpezhe-Kurt Kui pipeline linking the two countries, thereby becoming the first (and so far, only) natural gas export pipeline from Central Asia to bypass Russia. Although Gazprom and Turkmenistan resolved their pricing dispute in 1998, in order to reach its full natural gas export potential, Turkmenistan and other Caspian region natural gas producers must solve the problem of how to pipe their natural gas to consumers and receive hard currency at market prices in return.

New Export Options

In order to bring much-needed hard currency into their economies, Caspian region oil and natural gas producers are seeking to diversify their export options to reach new markets. With new production coming online as well, new transportation routes will be necessary to carry Caspian oil and natural gas to world markets. To handle all the region's oil that is slated for export, a number of Caspian region oil export pipelines are being developed or are under consideration. Likewise, there are several Caspian region natural gas export pipelines that have been proposed. Although there is no lack of export option proposals, questions remain as to *where* all these exports should go.

West?

The TRACECA Program (Transport System Europe-Caucasus-Asia, informally known as the Great Silk Road) was launched at a European Union (EU) conference in 1993. The EU conference brought together trade and transport ministers from the Central Asian and Caucasian republics to initiate a transport corridor on an West-East axis from Europe, across the Black Sea, through the Caucasus and the Caspian Sea to Central Asia.

In September 1998, twelve countries (including Azerbaijan, Bulgaria, Kazakhstan, Romania, Turkey, and Uzbekistan) signed a multilateral agreement known as the Baku Declaration to develop the transport corridor through closer economic integration of member countries, rehabilitation and development of new transportation infrastructure, and by fostering stability and trust in the region. The planned Baku-Ceyhan Main Export Pipeline to transport oil from Azerbaijan to Turkey and then to European consumers is the main component of this cooperation.

In addition, the EU has sponsored the Interstate Oil and Gas Transport to Europe (INOGATE) program, which appraises oil and natural gas exports routes from Central Asia and the Caspian, and routes for shipping energy to Europe. INOGATE is run through the EU's Technical Assistance to the Commonwealth of Independent States (TACIS) program.

East?

However, there is some question as to whether Europe is the right destination for Caspian oil and natural gas. Oil demand over the next 10 to 15 years in Europe is expected to grow by little more than 1 million bbl/d. Oil exports eastward, on the other hand, could serve Asian markets, where demand for oil is expected to grow by 10 million bbl/d over the next 10 to 15 years. In particular, Chinese oil consumption is projected to rise dramatically.

To supply this Asian demand, though, would necessitate building some of the world's longest pipelines. Geographical considerations would force any pipelines to head north of the impassable mountains of Kyrgyzstan and Tajikistan across the vast, desolate Kazakh steppe, thereby adding even more length (and cost) to any eastward pipelines.

South?

An additional way for Caspian region exporters to supply Asian demand would be to pipe oil and natural gas south. This would mean sending oil and natural gas through either Afghanistan or Iran. The Afghanistan option, which Turkmenistan has been promoting, would entail building pipelines across war-ravaged Afghan territory to reach markets in Pakistan and possibly India. With the ouster of the Taliban in Afghanistan in December 2001, proposals to build a Trans-Afghan natural gas pipeline and the Central Asian Oil Pipeline have re-emerged, but neither pipeline is realistic in the short-term.

The Iranian route for natural gas would pipe Caspian region natural gas (from Azerbaijan, Uzbekistan, and Turkmenistan) to Iran's southern coast, then eastward to Pakistan, while the oil route would take oil to the Persian Gulf, then load it onto tankers for further trans-shipment. Turkmenistan and Kazakhstan also have initiated low-volume oil "swap" deals with Iran, delivering oil in tankers to refineries in Iran's northern regions in exchange for similar volumes of crude at Iranian ports in the Persian Gulf. However, any significant investment in Iran would be problematic under the Iran and Libya Sanctions Act, which imposes sanctions on non-U.S. companies investing in the Iranian oil and natural gas sectors. U.S. companies already are prohibited from conducting business with Iran under U.S. law.

North or Northwest?

For its part, Russia itself has proposed multiple pipeline routes that utilize Russian oil pipelines to transport oil to new outlets being developed on the Baltic and Black Seas. In addition to the Caspian Pipeline Consortium's Tengiz-Novorossiisk pipeline, Russia's Baltic Pipeline System became operational in December 2001, and the country is working with Croatia to connect the Adria pipeline with the southern Druzhba pipeline. Reversing the flows in the Adria pipeline and tying it to the southern Druzhba route will allow oil exports from the Caspian to run via Russia's pipeline system, across Ukraine and Hungary, and then terminate at the Croatian deep-sea Adriatic port of Omisalj.

In addition, Russia already has the most extensive natural gas network in the region, and the system's capacity could be increased to allow for additional Caspian region natural gas exports via Russia. However, there are political and security questions as to whether the newly independent states of the former Soviet Union should rely on Russia (or any other country) as their sole export outlet, and Caspian region producers already have expressed their desire to diversify their export options.

Bosporus/Black Sea Issues

A major problem with additional Caspian oil exports heading west is the increasing congestion in the Bosporus Straits. Turkey has raised concerns about the ability of the Bosporus Straits, already a major chokepoint for oil tankers, to handle additional tanker traffic. Most of the existing Russian oil export pipelines terminate at the Russian Black Sea port of Novorossiisk, requiring tankers to transit the Black Sea and pass through the Bosporus Straits in order to gain access to the Mediterranean and world markets.

Already, Turkey has stated its environmental concerns about a possible collision (and ensuing oil spill) in the Straits as a result of increased tanker traffic from the launch of the Caspian Pipeline Consortium's Tengiz-Novorossiisk pipeline in March 2001. The first tanker with CPC oil was loaded at Novorossiisk in October 2001, and exports are expected to increase to 400,000 bbl/d by the end of 2002. As a result, there already are a number of options under consideration for oil transiting the Black Sea to bypass the Bosporus Straits.


Tanker passing through the Bosporus Straits.
Source: Andrew Neff

Regional Conflicts

In almost any direction, Caspian region export pipelines may be subject to regional conflicts, an additional complication in determining final routes.

Despite the ouster of the Taliban government in December 2001, Afghanistan remains scarred and unstable after 23 years of war. The Azerbaijan-Armenia war over the Armenian-populated Nagorno-Karabakh enclave in Azerbaijan has yet to be resolved. Separatist conflicts in Abkhazia and Ossetia in Georgia flared in the mid-1990's. Russia's war with Chechnya has devastated the region around Grozny in southern Russia. In addition, the Uzbek government has been cracking down on Islamic fundamentalism in Uzbekistan, tensions between rivals Pakistan and India remain high, and the Caspian littoral states themselves have taken to bickering over territorial claims in the Sea.

Nevertheless, several export pipelines from the Caspian region already are completed or under construction, and Caspian region exports are already transiting the Caucasus. While the hope is that export pipelines will provide an economic boost to the region, thereby bringing peace and prosperity to the troubled Caucasus and Caspian regions in the long run, the fear is that in the short-term, the fierce competition over pipeline routes and export options will lead to greater instability.

Sources for this report include: Agence France Presse, BBC Monitoring Central Asia Unit, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, The Economist, Environment News Service, The Financial Times, FSU Oil and Gas Monitor, Hart's European Fuels News, Interfax News Agency, The Moscow Times, PlanEcon, PR Newswire, Radio Free Europe/Radio Liberty, Reuters, RosBusinessConsulting Database, The Times of Central Asia, Turkish Business News, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, and U.S. Department of State.

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July 2002

Kazakhstan: Major Oil and Natural Gas Projects

Name of Field/Project	Project Partners	Estimated Reserves	Projected Investment	Project Status
Aktobe	CNPC (China) 63%, Aktobemunaigaz 37%	1 billion barrels of oil	$4.1 billion	Producing 82,707 bbl/d of oil (end-May 2002); produced 8.8 Bcf of natural gas through first five months of 2002
Arman	Kerr-McGee-Oryx (U.S.) 50%, Kazmunaigaz 50%	--	--	Produced 6,000 bbl/d of oil in 2001.
Emba	Kazakhoil-Emba (Kazmunaigaz subsidiary) 51%, MOL Rt, Vegyepszer (Hungary) combined 49%	--	--	Producing 49,500 bbl/d of oil (end-May 2002); produced 1.5 Bcf of natural gas through first five months of 2002

Hurricane-Kumkol	Hurricane (Canada)	442 million barrels of crude oil; 67.9 billion cubic feet (Bcf) of natural gas	--	Producing 87,671 bbl/d of oil (end-May 2002); produced 1 Bcf of natural gas through first five months of 2002
Karachaganak	Karachaganak Integrated Organization (KIO): Agip (Italy) 32.5%; BG (U.K.) 32.5%; ChevronTexaco (U.S.) 20%; Lukoil (Russia) 15%	2.3 billion recoverable barrels of oil & gas condensate reserves; 16 Tcf of recoverable natural gas reserves	$4 billion for Phase Two	Producing 99,865 bbl/d of gas condensate (end-May 2002); produced 68.8 Bcf of of natural gas through first five months of 2002
Karazhanbasmunai	Nations Energy	--	--	Produced 10,300 bbl/d (8/98)
Kashagan	Agip Kazakhstan North Caspian Operating Company (Agip KCO) (formerly OKIOC): ENI-Agip (Italy) 16.67%; BG (U.K.) 16.67%; ExxonMobil (U.S.) 16.67%; TotalFinaElf (France/Belgium) 16.67%; Royal Dutch/Shell (U.K./Netherlands) 16.67%; Inpex 8.33%; Phillips (U.S.) 8.33	Approximately 40 billion barrels (up to 10 billion of which are thought to be recoverable)	Over $600 million spent since 1993	Second successful well (Kashagan West 1) drilled (3/01); exploration continuing, production by 2005
Kazgermunai	Veba Oel (Germany) 25%; EEG (Germany) 17.5%; IFC 7.5%	100 million barrels of oil	$300 million	Produced 1,170 bbl/d (8/98)

Kumkol-Lukoil	Lukoil (Russia)	Over 600 million barrels of oil	--	Produced 17,010 bbl/d (8/98)
Kurmangazy	Kazmunaigaz (50%), Rosneft/Gazprom (25%), 25% unassigned	--	--	Russia and Kazakhstan recently agreed on a plan to develop jointly the disputed field
Mangistau	Mangistaumunaigaz (Kazmunaigaz subsidiary) 100%	--	--	Producing 89,551 bbl/d of oil (end-May 2002); produced 2.4 Bcf of natural gas through first five months of 2002
Matin	Matoil S.A. (50%)	102 million barrels of oil	--	Producing 4,011 bbl/d (4/01)
North Buzachi	ChevronTexaco (U.S.) 65%, Nimir (Saudi Arabia) 35%	1 to 1.5 billion barrels of oil	Over $800 million	Development North Buzachi; 3rd test well drilled
Tengiz	TengizChevroil (TCO): ChevronTexaco (U.S.) 50%; ExxonMobil (U.S.) 25%; Kazmunaigaz 20%; LukArco (Russia) 5%	6 to 9 billion barrels of oil	$20 billion over 40 years	Producing 253,182 bbl/d of oil (end-May 2002); peak production of 750,000 bbl/d by 2010; produced 56 Bcf of natural gas through first five months of 2002

Tengiz-Novorossiisk Oil Pipeline	Caspian Pipeline Consortium (CPC): Russia 24%; Kazakhstan 19%; ChevronTexaco (U.S.) 15%; LukArco (Russia/U.S.) 12.5%; Rosneft-Shell (Russia-U.K./Netherlands) 7.5%; ExxonMobil (U.S.) 7.5%; Oman 7%; Agip (Italy) 2%; BG (U.K.) 2%; Kazakh Pipelines (Kazakhstan) 1.75%; Oryx (U.S.) 1.75%	990 mile oil pipeline from Tengiz oil field in Kazakhstan to Russian's Black Sea port of Novorossiisk; Phase I capacity: 565,000 bbl/d; Phase II capacity: 1.34 million bbl/d (2015)	$2.6 billion for Phase 1; $4.2 billion total when completed	First tanker loaded in Novorossiisk (10/01); exported 240,000 bbl/d in April 2002, volumes rising to 400,000 bbl/d by end-2002
Uzen	Uzenmunaigaz (Kazmunaigaz subsidiary) 100%	1.5 billion barrels of oil	--	Producing 94,467 bbl/d of oil (end-May 2002); produced 17.8 Bcf of natural gas through first five months of 2002

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September 2001

United Kingdom

With its significant North Sea reserves, the United Kingdom is a major European oil and natural gas producer. It is also one of the largest energy consumers in Europe.

Information contained in this report is the best available as of September 2001 and is subject to change.

BACKGROUND

The United Kingdom (official name: United Kingdom of Great Britain and Northern Ireland, abbreviated: UK) is a major political and economic world power and a close ally of the United States. It is also the world's fourth-largest economy. The country joined the European Union (EU) in 1973 (confirmed by referendum in 1975), but has no plans to join the common European currency, the euro, in the immediate future. Despite the UK's lack of participation in the euro, the country has continued to attract foreign direct investment (FDI) - about $517 billion total at the end of 2000, second in the world after the United States. The UK is an even larger exporter of capital - outward FDI at the end of 2000 totaled $902 billion, also second to the United States. The UK maintains a smaller public sector than many of its EU counterparts.

The UK, like most of the OECD, has seen growth rates decline in 2001. GDP growth in the UK is expected to decline to 2% in 2001, and will decline further still if the economy of the United States approaches a mild recession, as the UK economy is the second-closest linked to that of the United States of all the countries of the EU. This slowdown is also expected to decrease external demand, raising the trade deficit for 2001. Despite this, unemployment fell to a 26-year low in July 2001.

Given low inflation (under the government's target of 2.5% for 28 consecutive months) and the prospect of slackening growth (especially in the manufacturing sector), the Bank of England has cut interest rates four times in 2001, most recently in August.

The United Kingdom is by far the largest petroleum producer and exporter in the EU (Norway is not a member of the EU). It also is the largest producer and an important exporter of natural gas in the EU. Most of the UK's oil and gas reserves and production are located off the coast of Scotland, with the Scottish city of Aberdeen considered to be the oil and gas capital of the United Kingdom. The International Petroleum Exchange (IPE), the second-largest energy futures exchange in the world, is located in London. The second and third-largest publicly traded energy companies in the world in terms of market value, Royal Dutch/Shell and BP, respectively, are based in the UK (Royal Dutch/Shell is also based in the Netherlands). Because major UK energy companies are private, the imminent decline in British oil and gas production most likely will translate to an increase in UK companies' involvement abroad, mitigating the effect in the overall UK economy, though Scottish employment is particularly sensitive to North Sea production levels. The oil and gas industry represented about 12% of industrial capital investment, and 2% of total capital investment in 2000. The energy industry overall represents about 4% of GDP. The UK has high taxes on petroleum products, making for among the highest prices in the EU. High fuel prices caused protests and blockades in September 2000.

In July 1999, a Scottish Parliament met for the first time in almost 300 years. "Devolution" gives the Scottish Parliament the ability to tax its own citizens, plus jurisdiction over local issues such as education, health, transport, and agriculture. It has no effect on the economic and industrial structure of the United Kingdom, which remains a single market. Devolution has had no effect on North Sea oil and gas.

North Sea Oil and Gas

North Sea oil and gas reserves were first discovered in the 1960s. The North Sea did not emerge immediately as a key non-OPEC oil producing area, but North Sea production grew as major discoveries continued throughout the 1980s and into the 1990s. Although the region is a relatively high cost producer, its high quality crude oil, political stability, and proximity to major European consumer markets have allowed it to play a major role in world oil and gas markets.

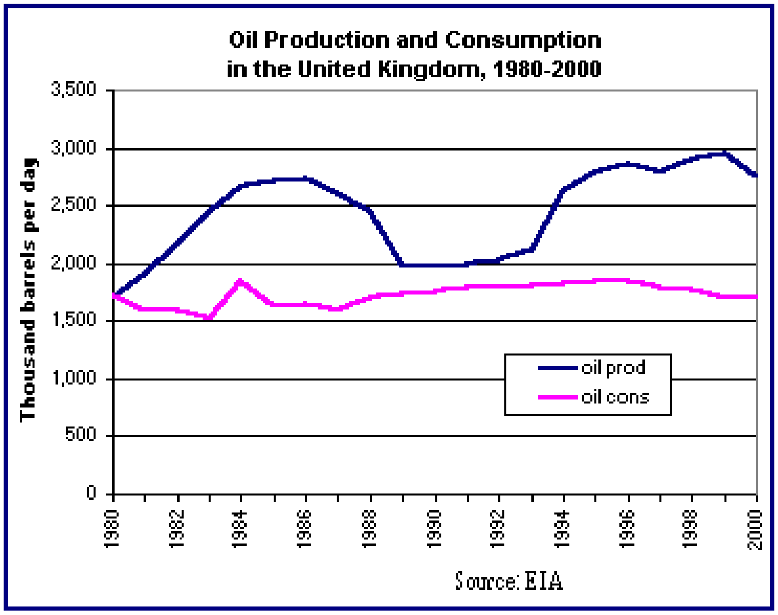
Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil. (Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field.) Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 450,000 bbl/d by 2005, but discussions are reported to be underway on building a pipeline spur from the Statfjord system to the Shell-run Brent pipeline to Sullom Voe. The increased throughput would support trade in the increasingly dated Brent price marker, extending its life as a price marker and reducing volatility in the 15-day Brent forward market, where liquidity has fallen to about 10 cargoes per delivery month compared with 300-400 deals per month in the early 1990s.

The North Sea is considered a "mature" area, with few large discoveries likely to be made. Only a few frontier areas hold the possibility of further discoveries of large oil and gas fields. In both of the major North Sea producing nations, Norway and the UK, government and industry are taking steps to restructure their oil and gas sectors to make them more internationally competitive.

OIL

The UK holds about 5 billion barrels of proven oil reserves, almost all of which is located in the North Sea. Most of the country's production comes from basins east of Scotland in the central North Sea.

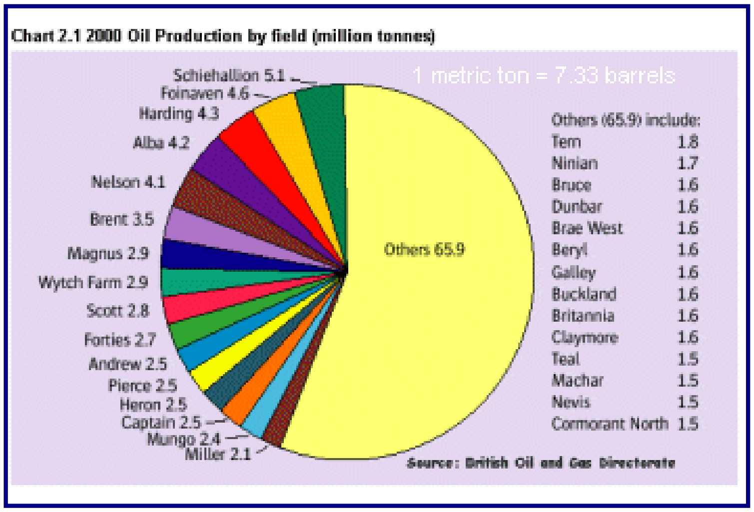
The northern North Sea (east of the Shetland Islands) also holds considerable reserves, and smaller deposits are located in the North Atlantic Ocean, west of the Shetland Islands. There are over 100 oil and gas fields currently onstream, and several hundred companies are active in the area. In 2000, the United Kingdom's production declined to 2.75 million barrels per day (bbl/d), down from a historical high of 2.95 million bbl/d in 1999. Production is expected to decline by 85,000 bbl/d in 2001. Most of the UK's crude oil production ranges in gravity from 30º to 40º API. Most high quality crude is exported, while cheaper, lower quality (mainly from the Middle East) crude oils are imported for refining. Unit costs for UK oilfields averaged just above $15 per barrel in 2000, though fields that started production in the 1990s have lower costs.



The domestic UK oil and gas industry is expected to decline as reserves are depleted in the coming decade. The British Oil and Gas Industry Task Force was set up in 1998 to bring together government departments and oil and gas industry representatives (the oil and gas industry is 100% in the hands of the private sector) to discuss the future of the industry. A successor body to the Task Force, known as "PILOT", now has been created to oversee the execution of Task Force recommendations and future developments. Government and industry are interested in collaborating to facilitate a "gentle decline" in British North Sea production, a component of which involves shifting focus from small numbers of very large projects to larger numbers of smaller projects.

Production

The number of fields under development or in production in the UK at the end of 2000 was 264. Just two fields ceased production, Bladen and Blenheim. Oil production from six offshore fields commenced in 2000: Bittern, Cook, Guillemot West, Guillemot North West, Shearwater (condensate), and Keith. In 2001, as of July, four new offshore oil fields were approved for development by the British Oil and Gas Directorate: Halley, Hannay, Kestrel, and Otter; and the Angus field was approved for redevelopment.



In December 2000, the British government gave approval to four new projects that will result in $1.5 billion in new investment in the British North Sea: (1) a £320 milliongas pipeline from the Shetland Islands to the Magnus oil field that takes suplus gas from Sullom Voe oil terminal on the Shetland Islands to be reinjected for enhanced recovery in the Magnus field; (2) a floating platform to drill for oil in the Leadon field which was discovered in 1979, but so far undeveloped, that is expected to yield 50,000 bbl/d of oil equivalent (see below); (3) further development by BP of the Foinaven oil field; and (4) Ranger Oil's (subsidiary of Canadian Natural Resources Limited) production in the Kyle field, which started in April 2001 at 7,000 bbl/d, in addition to gas production. Total investment spending in the UK continental shelf in 2000 was about £3 billion, though continued high oil prices make it likely that investment will increase for 2001. Most new developments will be subsea, using existing infrastructure, instead of new platforms.

As noted above, production commenced in April 2000 from the Bittern, Guillermot West, and Guillermot North West fields by means of the Amerada-Hess operated Triton FPSO. About 78% of the content is British, and the three fields have reserves of about 140 million barrels of oil and 180 billion cubic feet (Bcf) of gas. Expected field life is 13 years and daily production is 60,000 bbl/d. Another development is the £350-million expansion Area B to Texaco's Captain field completed in December 2000 allows production to increase by 25,000 bbl/d to 85,000 bbl/d and will extend the field's life to beyond 2015.

Some of the smaller projects planned for the British North Sea include development of the Jade and Blake fields. In January 2000, the British subsidiary of Phillips Petroleum (operator) and its partners British Gas, Texaco, Agip, and OMV received approval from DTI to develop the Jade field. The field is expected to produce 15,000 bbl/d of crude oil and 200 million cubic feet per day (Mmcf/d) of natural gas after it comes onstream in late 2001. The BG-operated Blake field represents the opening up of the Outer Moray Firth for new discoveries and developments. It has a subsea tie-back to the existing Bleo Holm FPSO, and will extend the life of the existing Ross field. Production is expected to start in third-quarter 2001.

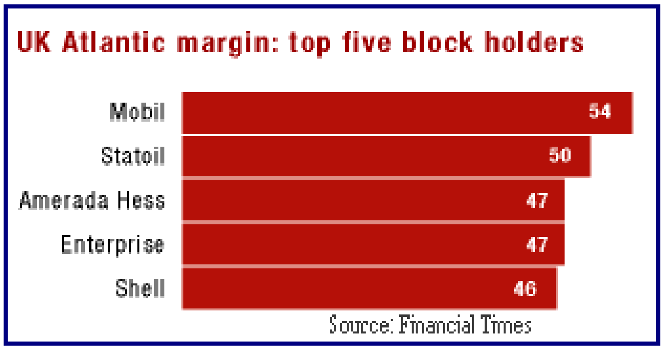
Another important development is the Skene field, which is being developed by operator ExxonMobil as a subsea tie-back to the Beryl Alpha platform. This field has a complex mix of hydrocarbons, including crude oil and condensate, that is estimated to be about 100 million barrels of oil equivalent. Only the implementation of the latest technology using a heated flowline bundle has made recovery possible. It is expected to come online in April 2002.

A larger project that was given approval in 2000 is the development of the Leadon field. It was discovered in 1979, but became economically viable with the discovery of a northern extension of the field. The Canadian company Kerr-McGee-operated field is expected to commence production in early 2002, and will peak at 40,000 bbl/d of crude oil.

Europe's largest on-shore oilfield is Wytch Farm. Estimated reserves are 500 million barrels. Egdon Exploration is active in the area, and it is hoped that even smaller fields can be economically viable as they are on-shore. Other smaller on-shore fields are clustered in east-central England.

Industry Structure

Industry reorganization that started with BP's 1998 merger with Amoco continues. The merged BP Amoco, (now simply BP) already one of the world's largest petroleum companies, announced in April 1999 its intentions to take over Los Angeles-based Atlantic Richfield (Arco), which was completed in April 2000. The merged company is truly global and is the world's third-largest publicly traded oil and gas company. Most of the majors have a share of UK North Sea production, including BP, Chevron, Conoco, ENI, ExxonMobil, Royal Dutch/Shell, Texaco, and TotalFinaElf. Amerada Hess, Enterprise, and Statoil also have large shares. The graphic shows the number of blocks held by each top-ranking company in 2000.



BP Exploration is managed from Aberdeen, Scotland (as are most other companies that are active in the British North Sea). BP produces oil and gas and brings ashore 40% of the UK's total production through the Forties Pipeline System to Grangemouth, Scotland. BP Amoco has producing fields in the North Sea and, since the end of 1997, in the North Atlantic, west of the Shetland Islands. It operates the Sullom Voe oil terminal in the Shetlands, which is Europe's largest oil terminal. The 206,000-bbl/d oil refinery and petrochemical complex at Grangemouth represents one of Scotland's largest industrial complexes.

British independent oil companies, important in the North Sea oil scene, were particularly hard hit by the oil price collapse of 1998. As a result, the major five independents at the time, Enterprise, Lasmo, Premier, British-Borneo, and Cairn, were hesitant to approve new investment and development in 1999-2000, though Enterprise has now begun more investment and development. The consolidation sweeping the oil majors has affected the independents. Enterprise, the largest British independent, unsuccessfully attempted to take over the second largest, Lasmo, in the spring of 1999. Enterprise's UK production was 164,907 barrels of oil equivalent per day in 2000. In 2000, Italian oil and gas giant ENI began to acquire British independents, British-Borneo in March 2000, and Lasmo in February 2001. This gives ENI a presence in the North Sea, and increases its worldwide oil and gas assets, particularly in Asia. Regarding the remaining two independents, Premier is heavily focused outside of the UK, and Cairn's production and reserves are very small, even for an independent.

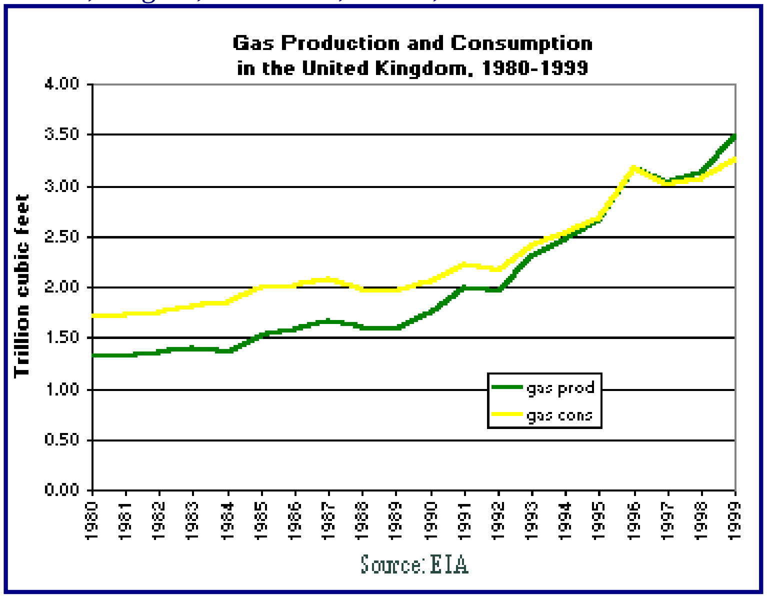
Downstream

The UK's crude oil refining capacity is approximately 1.77 million barrels per day, just slightly more than the country's consumption. However, the UK imports and exports refined products because British refineries produce an excess of some grades and products and insufficient quantities of others for local demand. Additionally, demand for gasoline varies seasonally. The largest refinery is ExxonMobil's (Esso's) 311,240-bbl/d Fawley refinery in Southhampton, one of the largest in Europe and marine tanker accessible. It also has a pipeline to the on-shore Wytch Farm field. The 100,000-bbl/d Port Clarence Phillips-Imperial Petroleum refinery at North Tees is connected by pipeline to the Phillips Consortium Ekofisk Oil Terminal at Seal Sands, giving it a direct feed from the North Sea. The Grangemouth refinery is also directly connected to the North Sea through the Forties Pipeline System.

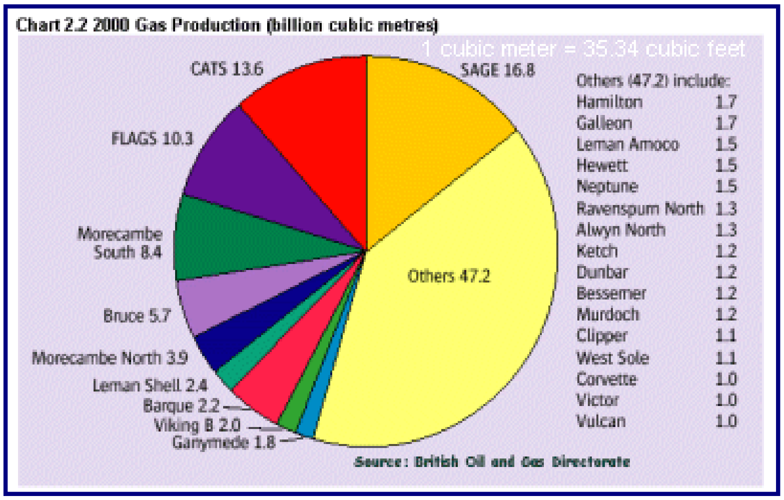
Petroleum products represented 45% of final energy consumption in 2000. The retail gasoline market is dominated by Esso (ExxonMobil), BP, Shell, TotalFinaElf, Texaco, and Conoco, which together account for 58% of gasoline sales. Supermarkets now account for 8% of retail sales. Total retail sales were 28 billion liters (7.4 billion gallons) in 2000. The transport sector consumed 74% of petroleum products in 2000, whereas the energy industry consumed just 7%. Fuel oil use has declined 30% since 1998, as industrial and home-heating demand has dropped in favor of gas.

NATURAL GAS

The UK contains an estimated 26.8 trillion cubic feet (Tcf) of natural gas reserves, most of which are in non-associated gas fields located off the English coast in the Southern Gas Basin, adjacent to the Dutch North Sea sector. The UK shares the declining Frigg field with Norway (39.18% to the UK), which is expected to be shut down in 2002, and has small share of the 0.44-Tcf Statfjord field (14.53%). There are a few small fields on-shore. The Irish Sea contains the large Morecambe and Hamilton fields. Morecambe alone accounts for up to 20% of British natural gas production. Key producing gas fields in the North Sea include BP's 5.7-Tcf Leman, Chevron and Conoco's 3-Tcf Brittania, Shell's 1.7-Tcf Indefatigable and 0.8-Tcf Clipper, and TotalFinaElf's 0.85 Tcf Elgin. Key pipelines are the Scottish Area Gas Evacuation (SAGE) system to the St Fergus Terminal, which handles gas produced from a number of North Sea fields, including Britannia, the Beryl and Brae areas, and others in the central/northern North Sea, the Central Area Transmission System (CATS) that also goes to the Central North Sea, and takes gas from several fields, including Everest, Judy, and Jade, and others, and the Far North Liquids and Associated Gas System (FLAGS) that takes gas from the northern North Sea, including the Brent, Magnus, Cormorant, Ninian, and Hutton fields.



The largest project to come online in 2001 (in March) in the British North Sea is the TotalFinaElf-operated Elgin/Franklin platform, which might prove to be the last big North Sea production platform. It is the world's largest high-pressure, high temperature development. The Elgin/Franklin platform has extensive processing facilities, unlike most North Sea platforms. The $2.3-billion platform is expected to last for 22 years in its location in the central North Sea, in the Graben area, off the coast of Scotland. It is to produce 700 million barrels of oil equivalent, about half condensate and half natural gas. This equates to peak production of 350 million cubic feet per day (Mmcf/d) of natural gas. The export pipelines are shared with the Shearwater field, and include a 294-mile gas pipeline to Bacton and a 24-mile condensate pipeline to the Marnock platform. The Shell-operated Shearwater field in the central North Sea was inaugurated in September 2000, and has reserves of 0.71 Tcf natural gas and 110 million barrels of condensate. Gas production is expected to peak at 375 Mmcf/d.



The Brigantine cluster is the most important recent development in the Southern Gas Basin. It is three fields with two platforms using extended reach horizontal wells to get at reserves of 0.27 Tcf. Shell is the operator, and production of 130 Mmcf/d commenced in the first quarter of 2001. There is a 12-mile pipeline to the Corvette platform, which is connected indirectly with Bacton.

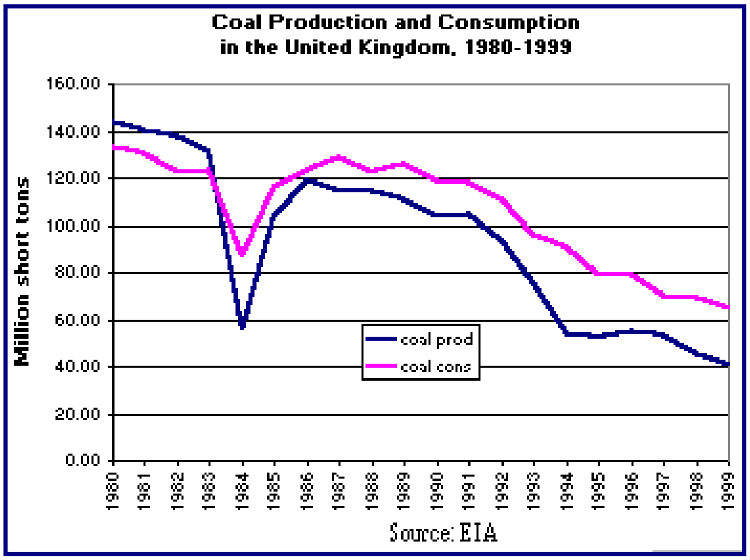
British Gas was the monopoly supplier to the interruptible market until the passage of the 1995 Gas Act, which split the company into supply and shipping (British Gas Trading Limited) and while other functions remained with British Gas, including transport subsidiary Transco. In 1997, Centrica was demerged from from British Gas, and British Gas was renamed BG. Centrica is the holding company for British Gas Trading, British Gas Services, the Retail Energy Centers, and is the producer in the Morecambe fields. BG retained Transco, along with exploration and production, international downstream, R&D and properties. In October 2000, BG again split, with Transco becoming part of a separate holding company Lattice Group. Independent Gas suppliers entered the firm (non-tariff) market in 1990, but the larger interruptible market (smaller customers) brought in competition in 1995. The consumer gas market was deregulated by region from October 1997 to June 1998, such that all residential and commercial customers could choose their supplier at the end of this process. At the end of 2000, suppliers other than British Gas Trading had captured 20-30% of the market in many regions of the UK. In July 2001, Houston-based Dynegy purchased BG Storage from what remains of BG for $590 million, acquiring gas production wells and platforms, salt caverns, pipelines, and a natural gas processing terminal.

The UK's gas and electricity regulatory body is the Office of Gas and Electricity Markets (Ofgem). Ofgem has proposed reforming price controls on Transco's pipeline usage fees. The privatization of the UK's gas industry, leading to an increased gas supply and reduced prices, has helped gas to replace much of the UK's reliance on coal as a source for electricity generation. The natural gas share of utility fuels was 1% in 1988 and is expected to increase to almost 50% by 2010. Privatization in the UK has progressed well in advance of EU requirements.

In 1998, the UK-Continent Gas Interconnector pipeline was opened, with terminals at Bacton, England and Zeebrugge, Belgium. This is the first natural gas pipeline linking the United Kingdom to the European continent. A new pipeline to connect Ireland to Scottish gas sources in the Corrib field was approved in November 1999, and a plan to connect Ireland to England via Wales was announced in April 2000. A pipeline would run from Manchester, England, underground to Wales, and then under the Irish Sea to just north of Dublin. There is currently one pipeline linking Britain and Ireland, connecting Ireland to Scottish gas sources. Despite these pipeline projects, the UK will remain a much smaller natural gas exporter than North Sea neighbor Norway, and will eventually become a net importer as the UK begins to import Norwegian gas again. Norway had once supplied up to a quarter of British demand in the 1980s, but this dwindled as the Frigg field that supplied the gas was depleted. The new Vesterled gas pipeline, set to begin operations October 1, 2001, will be one of the ways Norwegian gas may enter the UK. Vesterled will connect the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gasfields, and from there to other areas of the Norwegian North Sea such as the Ormen Lange gasfield that is scheduled to come on stream in 2006. In July 2001, BP announced a 15-year contract to buy 56.5 billion cubic feet (Bcf) natural gas per year from Statoil. However, Statoil has indicated that it would not import large volumes of gas through Vesterled unless Britain changed its pricing system for bringing gas onshore from North Sea fields. Statoil officials have asserted that the UK's system of auctioning entry capacity, or access rights to the national pipeline system, had produced volatile, very high prices.

COAL

Coal production and consumption in the United Kingdom have decreased dramatically since 1986. UK coal production fell from 119 million short tons (Mmst) in 1986 to 40.9 Mmst in 1999. Production fell again in 2000, but demand rose, increasing imports. In 2000, steam coal accounted for 80% of coal demand, coking coal for 15%, and anthracite for 5%. Electricity demand accounted for 95% of demand for steam coal and 46.5% of demand for anthracite. In the late 1980s, coal accounted for about two-thirds of the United Kingdom's thermal electricity production. Currently, less than half of UK thermal electricity is coal-fired, and the figure is expected to fall below one-third by the end of the decade. Coal mines are located primarily in central and northern England and southern Wales, with some coal mines also found in southern Scotland. The UK produced 40.5 million tons of bituminous coal and 409 thousand tons of anthracite coal in 1999. The UK also produces coke-oven coke in quantities such that it is self-sufficient. Nevertheless, net imports of coal in 1999 were 23.9 million tons.



Between 1984 and 1985, the British coal miners' union staged a year-long strike. The strike dramatically altered energy production and consumption patterns in the United Kingdom for that year and precipitated the longer term decline of the industry (see graph). Employment in the industry has plummeted since the late 1980s. The United Kingdom began liberalizing its electricity market in 1989, and this liberalization is one of the major reasons for the decline of the country's coal industry. Prior to the privatization of electricity, the cost of domestic coal to electric utilities had far exceeded the cost of coal traded in international markets. The Central Electricity Generation Board (CEGB) had been the primary purchaser of British coal. The CEGB largely subsidized the British coal industry, purchasing domestic coal at above world market prices and then passing on those costs to consumers. This ended when National Power and PowerGen, two private electricity generation companies, were formed in the early 1990s, weakening the bargaining power of British Coal, the national coal company.

In 1992, the British coal industry reached a turning point. Growing competition from increasingly available natural gas, the imminent removal of the regional electricity companies' captive franchise supply markets, and newly-enacted pollution abatement goals all worked to initiate the steady decline of the industry. The industry was privatized in 1994, at which point RJB Mining bought the major British Coal assets and become the country's major producer. Mining Scotland and Celtic Energy are the other two remaining companies. The UK coal industry had not received any subsidies since 1995, but in November 2000 the European Commission approved a modernization plan and aid scheme. The aid would go toward mines/production units that have long-term economic viability on the world market, but are having temporary difficulties as they restructure in an effort to reduce production costs. The total amount of aid will not exceed £110 million, and two disbursements of £25 million and £21 million have been made so far. Production costs over the period 1992 to 1999 already fell 35%, and the expectation is that these costs can fall further still before the aid scheme expires in July 2002.

New EU environmental directives are expected to further increase British coal production costs, leading some analysts to predict an end to the United Kingdom's coal industry in the early 2000s. RJB Mining is more optimistic about the future of British coal. RJB maintains that foreign coal prices will increase, making British coal more competitive, and that clean coal technology will allow power stations to burn increased amounts of coal without increased greenhouse gas emissions. Higher natural gas prices, gas-fired power plant outages for maintenance and repair, and reduced nuclear power led to a 14% increase in coal consumption by power producers in 2000.

ELECTRICITY

The United Kingdom has 70 million kilowatts of installed electric capacity, about 80% of which is thermal, 18% nuclear, and 2% hydropower. The country generated 342.8 billion kilowatt hours (bkwh) of electricity in 1999, making it the third-largest electricity market in Europe (behind Germany and France).

Electricity privatization began in the early 1990s, and the final phase of transition ended in May 1999. Initially, all non-nuclear state-owned power stations were privatized and four major generating companies -- PowerGen and National Power in England and Wales, and ScottishPower and Hydro-Electric in Scotland -- were formed to operate the stations. The grid distribution system in England and Wales became the property of the National Grid Company. Regional Electricity Boards were privatized as separate distribution companies. Large customers were the first to be able to choose their suppliers, with all small customers (below 100 kW peak load) being able to choose by May 1999.

The number of electric generation companies in the United Kingdom has increased to 27 as a result of the liberalization process, according to DTI, such that 40% of the UK's electricity was generated by these new companies in 2000. In March 2001, the structure of the electricity industry changed yet again. Under the former system, generators and suppliers in England and Wales traded electricity through the electricity pool, which was regulated by the National Grid Company, owner of the transmission network. The New Electricity Trading Arrangements (NETA) changed this to a system based on bilateral trading between generators, suppliers, traders, and customers. The system includes fowards and futures markets, a balancing mechanism to enable the National Grid Company to balance the system, and a settlement process. Dallas-based TXU purchased United Utilities' retail electricity and natural gas business, Norweb Energi, for $465 million in August 2000. This, added to TXU's European retail business Eastern Energy, creates the UK's largest electricity retailer, with over 5.6 million customers. Powergen, with 2.6 million retail customers as well as 14% of electricity generation in England and Wales, merged with Louisville-based LG&E Energy in December 2000.

In Scotland, the two main companies, Scottish Power and Scottish and Southern Energy, cover the full range of electricity provision. Ofgem has made proposals to further reform the Scottish power market. Northern Ireland, part of the United Kingdom but not part of Great Britain, is served by Northern Ireland Electricity, one of the largest companies in Northern Ireland and part of the Viridian Group. Northern Ireland has a separate electricity and gas regulatory body, Ofreg. The grids of Northern Ireland and the Republic of Ireland are connected for electricity import/export.

Nuclear

In 1995, the government announced that it would privatize its more modern nuclear stations while retaining ownership of older stations. In 1996, more modern stations were privatized and British Energy became the holding company of Nuclear Electric and Scottish Nuclear, which merged in 1998 to form British Energy Generation, the nation's largest private nuclear generator and the world's first wholly privatized nuclear utility. British Energy operates eight nuclear power stations in the UK (as well as several in the U.S. through its AmerGen subsidiary that is jointly owned with PECO). Each station consists of two advanced gas-cooled reactors, except Sizewell B, which is a modern pressurized-water reactor. Nuclear power stations were not privatized simultaneously with non-nuclear stations. No new plants have been built since 1995, but because of limited domestic coal and gas reserves in the long run, new construction is under discussion, at least to maintain nuclear's market share as older nuclear plants are retired. Of the UK's 33 reactors, 26 are of the old Magnox design. Six of the Magnox reactors are being decommissioned, as well as the Dounreay prototype fast reactor. The remaining Magnox plants are run by the state-owned British Nuclear Fuels. British Nuclear Fuels operates the Sellafield reprocessing plant, and is one of only two companies in the world that provides reprocessing and recycling technologies. The British nuclear industry is regulated by the Department of Trade and Industry's Nuclear Directorate.

ENVIRONMENT

With a reduction in sulfur dioxide and carbon dioxide emissions, environmental conditions in the United Kingdom have improved over the past couple of decades. Some of these environmental improvements, such as a reduction in air pollution, can be attributed to the United Kingdom's energy use choices. Partially as a result of deregulation and the elimination of coal subsidies, coal's share of total primary energy consumption is gradually being replaced by natural gas.

Improvements in energy efficiency have led to a gradual reduction in both energy and carbon intensity. In 1980, energy intensity in the United Kingdom registered 11.70 thousand Btu per $1990, decreasing to 8.37 thousand Btu per $1990 in 1999, a 27% decline. Similarly, carbon intensity in 1999 registered 0.13 metric tons of carbon per thousand $1990, a 45% decrease from 1980 levels. Per capita energy consumption, at 167.8 million Btu in 1999, is rising gradually.

As the United Kingdom enters the 21st century, many energy and environment-related policies reflect the country's awareness of climate change issues. With introduction of the Climate Change Levy in 2001, and its exemption for renewable energy resources like solar and wind, these alternative sources of energy are beginning to gain more attention. For example, the United Kingdom hopes to increase the share of electricity generated by renewables from the current 2%, to 10% by 2010.

Sources for this report include: Aberdeen Press & Journal; CIA World Factbook; Economist; Economist Intelligence Unit ViewsWire; Financial Times; Hart's European Offshore Petroleum Newsletter; Oil & Gas Journal; Petroleum Economist; Petroleum Intelligence Weekly; The Scotsman; U.K. Department of Trade and Industry; U.S. Energy Information Administration; WEFA World Economic Outlook.

COUNTRY OVERVIEW

Head of State: Queen Elizabeth II
Prime Minister: Anthony (Tony) Blair, re-elected June 2001
Population (2000E): 59.5 million
Location/Size: Western Europe, islands including the northern one-sixth of the island of Ireland between the North Atlantic Ocean and the North Sea, northwest of France/244,820 sq km (slightly smaller than Oregon)
Capital City: London
Language: English
Ethnic groups: English 81.5%, Scottish 9.6%, Irish 2.4%, Welsh 1.9%, Ulster 1.8%, West Indian, Indian, Pakistani, and other 2.8%
Religions: Anglican 27 million, Roman Catholic 9 million, Muslim 1 million, Presbyterian 800,000, Methodist 760,000, Sikh 400,000, Hindu 350,000, Jewish 300,000 (1991 est.)
Defense (8/98): Army, 113,900; Navy, 44,500; Air Force, 52,540

ECONOMIC OVERVIEW

Chancellor of the Exchequer: Gordon Brown
Currency: Pound sterling
Exchange Rate (9/04/01): 1 US Dollar = 0.69 pounds
Gross Domestic Product (GDP, 2000E): $1,415 billion
Real GDP Growth Rate (2000E): 3.0% **(2001F):** 2.0%
Inflation Rate (consumer prices, 2000E): 2.9% **(2001F):** 2.0%
Unemployment Rate (2000E): 3.7% **(2001F):** 3.4%
Merchandise Exports (2000E): $283 billion
Merchandise Imports (1999E): $327 billion
Major Trading Partners: United States, Germany, France, Netherlands
Major Exports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment
Major Imports: Food, beverages, and tobacco; crude materials, fuels, chemicals, machinery, transport equipment

ENERGY PROFILE

Secretary of State for Trade and Industry: Patricia Hewitt
Minister of State for Industry and Energy: Brian Wilson
Proven Oil Reserves (1/1/01): 5 billion barrels
Oil Production (2000): 2.75 million bbl/d, of which 2.48 million bbl/d was crude oil
Oil Consumption (2000): 1.7 million bbl/d
Crude Oil Refining Capacity (1/1/01): 1.77 million bbl/d
Net Oil Exports (2000): 1.05 million bbl/d
Natural Gas Reserves (1/1/01): 26.8 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 3.49 Tcf

Natural Gas Consumption (1999E):3.26 Tcf
Natural Gas Net Exports (1999E): 0.02 Tcf
Major Systems: Brent, Ninian, Forties, Flotta, Fulmar
Major Fields: E. Brae, Brent, Forties, Magnus, Miller, Scott
Oil and Gas Companies: Amerada Hess, BP Amoco, BHP, Chevron, ExxonMobil, Kerr-McGee, Phillips, Ranger Oil, Shell, Texaco
Recoverable Coal Reserves (12/31/96E): 1.65 billion short tons
Coal Production (1999E): 40.9 million short tons (Mmst)
Coal Consumption (1999E): 64.8 Mmst
Electrical Generation Capacity (1/1/99): 69.9 gigawatts (79.7% thermal, 2.1% hydro, 18% nuclear, 0.2% other)
Electricity Generation (1999E): 342.8 billion kilowatt hours (bkwh)
Electricity Consumption (1999E): 333 bkwh

ENVIRONMENTAL OVERVIEW

Secretary of State for the Environment, Food, and Rural Affairs: Margaret Beckett
Total Energy Consumption (1999E): 9.9 quadrillion Btu* (2.6% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 152.4 million metric tons of carbon (2.5% of world carbon emissions)
Per Capita Energy Consumption (1999E): 167.8 million Btu (vs. U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 2.6 metric tons of carbon (vs. U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 8,365 Btu/$1990 (vs U.S. value of 12,638 Btu/$1990)**
Carbon Intensity (1999E): 0.13 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (37.0%), Residential (25.4%), Transportation (26.1%), Commercial (11.5%)
Sectoral Share of Carbon Emissions (1998E): Industrial (33.7%), Transportation (31.3%), Residential (24.3%), Commercial (10.6%),
Fuel Share of Energy Consumption (1999E): Oil (35.0%), Natural Gas (34.9%), Coal (15.7%)
Fuel Share of Carbon Emissions (1999E): Oil (41.2%), Natural Gas (33.4%), Coal (25.5%)
Renewable Energy Consumption (1998E): 137 trillion Btu* (15% increase from 1997)
Number of People per Motor Vehicle (1998): 2.3 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change. Under the negotiated Kyoto Protocol (signed on April 29th, 1998 - not yet ratified), the UK has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Sulfur dioxide emissions from power plants contribute to air pollution; some rivers polluted by agricultural wastes and coastal waters polluted because of large-scale disposal of sewage at sea.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Marine Life Conservation, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 1999.

Links

For more EIA information on the United Kingdom:
EIA - Country Information on the United Kingdom
Electricity Restructuring and Privatization in the United Kingdom

Links to other U.S. Government sites:
CIA World Factbook - United Kingdom
U.S. State Department Country Commercial Guides: Europe
U.S. State Department Consular Information Sheet
U.S. Geological Survey, map of the United Kingdom including oil fields

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British Petroleum
Royal Dutch/Shell
Energy Links for the UK from Online Energy Services
International Petroleum Exchange
Grampian Oil and Gas Directory (an online database of companies operating in Scotland)
Scottish Enterprise Energy Group
RJB Mining
Electricity Association
National Power
PowerGen
ScottishPower
National Grid
Northern Ireland Electricity
British Energy (nuclear generator)
British Nuclear Fuels
UK Energy Centre
Ofgem
Ofreg
Department of Trade and Industry
Department of Environment, Transport and the Regions
British Embassy in Washington, D.C.
Scottish Parliament
International Energy Agency United Kingdom 1998 Review
Royal Institute of International Affairs, Energy and Environmental Programme
European Commission Directorate General XVII (Energy)

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December 2001

Italy

Italy is almost entirely dependent on imports to meet its energy needs. The country's heavy reliance on foreign oil and gas sources such as Libya and Algeria has made energy security and diversification of *energy sources top concerns.*

The information contained in this report is the best available as of December 2001 and is subject to change.

BACKGROUND

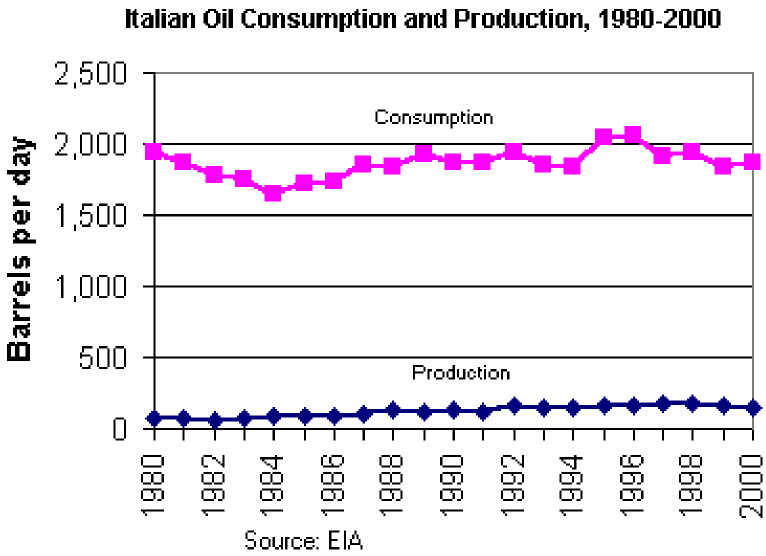
Italy is one of the world's largest economies, a founding member of the European Union (EU), a North Atlantic Treaty Alliance (NATO) member, and a member of the Group of Seven (G-7) industrialized nations. It joined the common European currency, the euro, on January 1, 1999.

Italy's 59th government since 1945 came to power in June 2001, headed by Prime Minister Silvio Berlusconi, leader of Forza Italia (who was also prime minister in 1994). The government is a coalition called "House of Freedoms" that gained a majority in both the Chamber of Deputies and the Senate, giving this government more power to implement its policies. Prior to Berlusconi's government, Italy had achieved a major economic policy objective: the reduction of its budget deficit to under 3% of gross domestic product (GDP) in order for Italy to comply with the EU's Stability and Growth Pact. The current government will have to continue to work to maintain this in light of low economic growth prospects in the near term. This slowdown has complicated the new government's promises radical economic reforms and tax cuts, but an economic slowdown has meant that with tax revenue decreases, making achievement of the government's target of a 1.1% budget deficit more difficult. The government has instead focused on cutting expenditures by streamlining public administration and on increasing revenues by taxing or confiscating grey and black market assets. Economic growth for 2001 is forecast at 1.5%.

EU membership has initiated important changes in Italy's energy sector, requiring privatization of the country's dominant energy monopolies. Italy's energy sector has been undergoing considerable restructuring in recent years. Eni, the partially state-held oil and gas conglomerate, along with its main subsidiaries, Agip (hydrocarbons exploration and production) and Snam (gas supplies and distribution), and the state-owned electricity company, Enel, all have been partially privatizated. The Italian government sold off shares of Eni between 1995 and 1998, and now holds 35% of the company. Privatization of Enel stalled but then moved ahead with a 32% sale in November 1999.

With limited domestic energy sources, Italy is highly dependent on energy imports. Historically, the country has relied heavily on imported oil, much of it from North Africa (mainly Algeria). In recent years, oil consumption has declined (although Italy remains one of the largest oil consumers in Western Europe) in favor of natural gas. Natural gas is a much cleaner fossil fuel that helps Italy to meet domestic, European, and broader international requirements for a cleaner environment. As with oil, North Africa is a large exporter of natural gas to Italy. There have been concerns that this reliance on North African sources has potentially negative implications for Italian energy security.

OIL



Italy holds 622 million barrels in proven oil reserves. In 2000, the country produced an estimated 145,000 barrels per day (bbl/d) of oil and consumed about 1.9 million bbl/d, making it more than 90% reliant on imports and one of Europe's largest oil importers. Former Italian colony Libya is Italy's main source of oil imports, and other major import sources (in order of magnitude) include Iran, Saudi Arabia, and Iraq. About 70% of Italy's oil imports are from the Middle East and North Africa. It is estimated that oil's share of Italy's energy consumption fell to just under 50% for the first time in over 20 years in 2000. Italy is in the process of decreasing its reliance on oil, especially for heating and electricity generation. Heating oil consumption in 2000 was about one-third of that of 1981 and fuel oil consumption has fallen 38% since 1995. Natural gas consumption is expected to rise as oil consumption falls in coming years.

Eni is Italy's largest integrated oil company, and the sixth-largest publicly traded oil company in the world. It dominates the upstream and downstream sectors in Italy. Worldwide petroleum production is approximately 1.3 million barrels of oil equivalent per day (boe/d) and the company had proven reserves at the end of 1999 of about 5.5 billion barrels of oil equivalent. Eni's Agip (Azienda Generale Italiana Petroli) division conducts hydrocarbon exploration and production and Eni's AgipPetroli subsidiary conducts downstream petroleum operations. Eni plans to increase production to 1.5 boe/d by 2002. In order to do this, Eni acquired British-Borneo Oil for $1.2 billion and Lasmo Oil for $8.5 billion in 2000. This increased Eni's reserves to 6 billion barrels of oil equivalent. These acquisitions give Eni interests in many areas, but especially in the North Sea and North Africa. Eni is very active in Iran, and in June 2001, Eni finalized a $1-billion contract with the government of Iran to develop the Darkhuwain oilfield.

Exploration and Production

Italy's oilfields are in the north of the country, onshore and offshore along the Adriatic and on and offshore Sicily. Two large Eni-operated fields, Villafortuna and Aquila have declined in recent years. In order to bolster energy security and reduce dependence on foreign sources, Italy is in the process of increasing domestic production. Eni is the operator in a joint venture with Britain's Enterprise to develop 600 million barrels of oil equivalent (including oil and associated natural gas) at Val d'Agri, in the southern Apennine region, considered to be Europe's most promising onshore development area. Output of 11,000 bbl/d from the fields began in 2000, but limited transport capacity prevented production reaching its target capacity of over 100,000 bbl/d. Construction on the 85-mile (136-kilometer), 150,000-bbl/d capacity pipeline connecting the fields to the Taranto refinery was completed by Enterprise in October 2001. Eni aims to have the fields producing at 47,000 bbl/d by the end of 2001, and 100,000 bbl/d by 2004.

In the Tempa Rossa field, neighboring the Val d'Agri fields, Eni is developing over 400 million barrels of oil equivalent in a joint venture with Enterprise (25%), TotalFinaElf (25%), and ExxonMobil (25%). Tempa Rossa has much heavier crude than Val d'Agri, and Eni reportedly plans to drill only 7 wells at Tempa Rossa (as opposed to 42 at Val d'Agri). Eni hopes to be producing 44,000 bbl/d by 2003. The crude oil will be treated on-site, and sent in batches through the new pipeline to the Taranto refinery.

Downstream

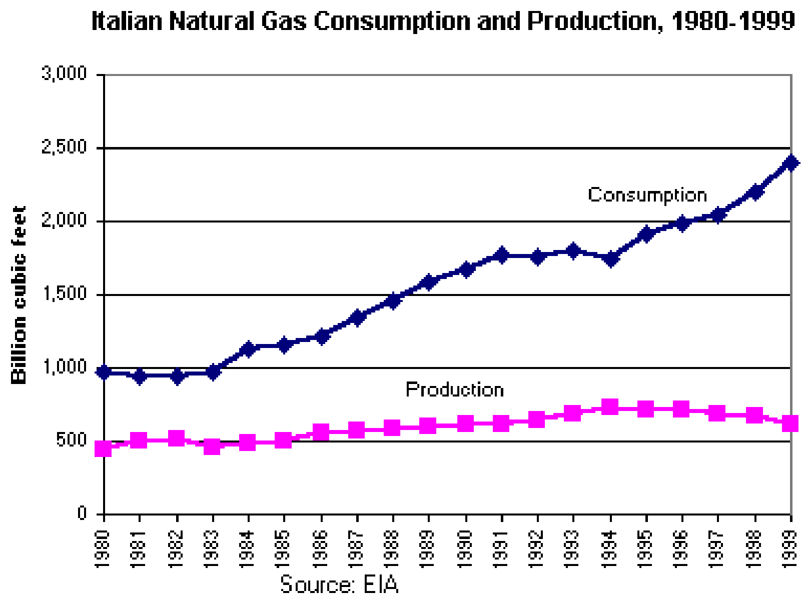
To ensure access to foreign oil, the Italian government has promoted Italy as an export refining center since the 1970s. There are large facilities along the Mediterranean coast and on Mediterranean islands, capable of processing a wide range of crude oils from North Africa and the Persian Gulf. As a result, Italy now has

Europe's largest surplus of refining capacity. However, refinery throughput was only 76% of capacity in 2000, and Italy is importing almost as much refined products as it exports. ENI operates six of the 16 major refineries in Italy. While underutilized, the Italian refineries remain attractive because of their ability to handle large tankers and process many different fuel types, and also because of their catalytic and hydro cracking abilities. ExxonMobil has a facility at Augusta on the Sicilian coast.

Italy has more gas stations than any other country in Europe. The government maintains that reducing the number of stations will help to reign in the cost of gasoline, but little progress has been made on this. In June 2000, in further efforts to address steadily increasing gasoline costs that went above $4 per gallon in the summer of 2000, Italy's antitrust commission found seven oil companies guilty of price-fixing at the retail level. The companies were fined about $300 million, and in November 2000 the courts upheld the ruling in an appeal but reduced the fine to about $200 million. In 2001, Eni sold 261 gasoline stations to Tamoil and 257 stations to other retailers as part of Eni's plan to concentrate more on upstream activities.

NATURAL GAS

Italy has natural gas reserves of 8.1 trillion cubic feet (Tcf). In 1999, the country produced 618 billion cubic feet (Bcf) and consumed 2.4 Tcf, relying on imports for roughly 75% of total consumption. Italy's natural gas consumption has risen substantially since imports began in the early 1970s with Eni gas purchases from the Netherlands and Russia. Italy currently is the third largest natural gas market in Europe, behind Germany and the United Kingdom. Natural gas use has increased substantially in recent years, especially for power generation. Natural gas now represents about 32% of total energy consumed in Italy, and this share is expected to grow in the coming years to 37% by 2010, according to Eni. Residential and commercial sectors acount for 36% of the market, industrial 33%, and electricity generation 31%. According to Enel officials, by 2010, 60% of electricity in Italy will be generated by natural gas and only 10% by oil.



Sector Organization

Eni, and its subsidiary Snam, control most of the Italian natural gas market. Eni supplied about 87% of the natural gas consumed by Italy in 2000 through its domestic production and contracted imports. Edison Gas, an independent power producer (IPP), is the only other significant company in the Italian natural gas sector, supplying about 5% of the market, but increasing rapidly, as natural gas from its new contract with Russia's Promgas is due to increase to 70.6 Bcf per year in 2002. Italian electricity conglomerate Enel also imports gas directly for its own generation activities. Italy has had very high rates of return for natural gas suppliers, transporters, and distributors, when compared with other European countries. Italian consumers pay among the highest natural gas prices in Europe, though there is significant regional variability in prices.

According to the EU Natural Gas Directive, passed in June 1998, member states must open their natural gas markets to competition. The Italian government unveiled plans for its liberalization process in May 2000, when the government directed that no single company can supply more than 50% of the natural gas sold to final users by 2003. No company will be able to send more than 75% of natural gas put into the transmission system beginning in 2002, and this will be reduced to 61% by 2009. The legislation also requires corporate and accounting separation of natural gas storage and transport activities. Snam will retain control of Italy's 30,000-kilometer (almost 19,000-mile) pipeline natural gas grid, but parent company Eni must split Snam's pipeline transport activities from commercial and sales activities. In late November 2001, the new company controlling the natural gas grid, Snam Rete Gas Italia, had an initial public offering (IPO) of 35% of its shares, which was heavily oversubscribed. The launching of Eni's new gas distribution company, Italgas Piu, was also in November 2001. Through Stoccaggi Gas Italia, Eni also operates a system where it stores and modulates natural gas. Eni's storage system is made up by 9 fields, 8 of which are located in Northern Italy (one of them is not yet operational) and one in Central Italy. Enel received permission from antitrust authorities to acquire five gas distribution companies in Nothern Italy in October 2001. They are: Arda Gas, Gead, Adda Gas, Geico, and Sein.

Imports

Most of Italy's natural gasfields are located in the Po Valley and offshore in the Adriatic. Preliminary estimates of 2000 production show a 4% decline compared to 1999. Hence, Italy is growing increasingly dependent on imports. Diversification of supply is an important issue, as Italy relies heavily on Algeria and Russia. In 2000, Italian natural gas sources were estimated to be 21% domestic, 34% Algerian, 30% Russian, and 9% Dutch -- Algerian figure includes liquefied natural gas (LNG) imported from Algeria. Snam imports from the Netherlands, Algeria, and Russia, Edison imports from Russian and Algeria, and Enel imports from Algeria and Nigeria. Snam, Edison, and Enel have contracts in place to increase purchases of Algerian and Russian natural gas.

Libya, Norway, and Qatar (LNG) are major alternative suppliers for Italian gas. The biggest project under consideration is the proposed construction of a pipeline to link Libya and Italy's southern island, Sicily. This $5.5 billion "West Libya Gas Project" was finalized in July 1999 as a joint venture between Libya's state-held National Oil Company and Eni, and an Eni contract to buy 141 Bcf per year from the joint venture was signed in early 2000. In November 2000, Gaz de France agreed to buy another 70.6 Bcf from Eni. The 600-kilometer (372-mile) pipeline "Green Stream" will run under the Mediterranean and connect with the TransMed pipeline. About 282.5 Bcf will be able to flow through the pipeline. Engineering work on the pipeline has begun. Start-up is planned for 2004. Snam began importing 6 billion cubic meters per year (212 Bcf) of Norwegian natural gas through existing pipelines in October 2001, and will continue to do so for 24 years.

Liquefied Natural Gas

LNG is becoming increasingly important in Italy. Italy receives Algerian LNG at its Panigaglia terminal near La Spezia, under a 25-year contract that runs until 2015. ENEL also signed a contract in 1992 under which Nigerian LNG will be delivered to France and swapped out to ENEL for 22 years, beginning in 1999. In June 2001, Edison signed an agreement to buy 3.5 tons of LNG per year (equivalent to 173 Bcf) from the fourth natural gas train of Rasgas in Qatar when the train is completed in 2005. Delivery will be made to a $430-million floating regasification terminal to be constructed by Edison and ExxonMobil 11 miles offshore Marina di Rovigo in the northern Adriatic. Enel has announced that it also has an agreement with Qatar and Repsol-YPF to import LNG, but exact volumes have not yet been determined. Enel is requesting clearance to build new LNG terminals at three different sites in the hopes that two will be approved.

COAL

Coal consumption in Italy is dominated by power generation, which is increasing, and coke production for steel, which is decreasing. Coal has played a small role in the Italian energy sector, and Italy produces almost no coal domestically. In 1999, less than 6% of Italy's primary energy demand was met with coal. The power sector is expected to increase its coal consumption in coming years, as Eni works to decrease reliance on imported oil, though coal will not be as important as natural gas. Clean coal technology will figure prominently in this increased coal usage, as EU environmental stipulations, Kyoto targets, and Italian public opinion demand that Italy's energy sector become increasingly clean. Italy's Vado Ligure power plant uses coal-over-coal reburn technology that substantially reduces harmful emissions.

Increased coal usage will be supplied by a combination of increased domestic production and increased imports. Main exporters of steam coal to Italy are South Africa, Indonesia, Colombia, and Australia.

ELECTRICITY

Italy has electric generation capacity of 65.5 million kilowatts, and in 1999 the country generated 247.7 billion kilowatt hours (bkwh) and consumed 272.4 bkwh. Generation is mostly from thermal sources, although the mix of thermal power is shifting away from oil and toward natural gas, and to a smaller extent toward coal, such that natural gas should be the dominant fuel source for electricity generation by the end of the decade. Non-hydro renewable electricity generation (mostly solar and geothermal) almost doubled in the 1990s, and over 2% of Italian electricity is now produced from renewable sources.

Italy's extensive electricity network is linked to its neighbors. Electricity imports come mostly from France and Switzerland. Construction of a new 164-kilometer (102-mile), 400-kilovolt underwater cable to link Italy and Greece was completed in March 2001, and is in the process of becoming operational.

Sector Organization

Enel is Italy's dominant electricity company. Enel, which was 100% owned by the Italian government until November 1999, produced about 70% of Italy's electricity usage in 2000. Enel is by some measures the largest publicly listed electricity company in the world. EU directives require member countries to open their electricity markets to competition and also require that no single company generate more than 50% of any member country's electricity by 2003. This has led to several important changes in Enel, Italy's former electricity monopolity, including partial privatization and the sale of some of its assets to reduce market share. The November 1999 Enel privatization stock sale was Europe's largest initial public offering (IPO). The government floated 32% of the company, which sold for 18 billion euros ($15 billion), on the Milan and New York stock exchanges. The government has been discussing plans to sell off an additional tranche in 2002. Before further privatization, Enel may sell off the main Italian electricity grid to the operator GRTN, as this will be easier to do while the government still has a majority share.

Also in late 1999, the company spun off three separate and independent generating companies in preparation for their eventual sale, totaling 15,000 megawatts (MW) of generation capacity: Eurogen, the largest company, is based in Rome and Milan; Elettrogen the second largest, is based in Rome and Piacenza; the smallest company, Interpower, is based in Naples and Rome. Elettrogen was sold to Endesa of Spain for 7.15 trillion lira in the summer of 2001. Eurogen was put up for sale in September 2001, and expectations are that it will be sold for about 8.4 trillion lira. No company will be allowed to acquire or hold stakes in more than one of the three companies, and no buyer will be able to be more than 30% government-held. This last requirement was to prevent Electricite de France (EdF) from acquiring these companies. EdF has been the subject of a dispute between Italy and the European Union. Because liberalization of the energy sector has proceeded at a slower pace in France, EdF has remained a state-owned company. EdF's purchase of privatized assets would in effect transfer them from Italy to France, so Italy has restricted such sales. The European Commission ruled in June 2001, that capital flows may not be restricted merely because of varying degrees of liberalization. However, the initial privatization sale may be restricted, but such restrictions can only be in place for a limited period, after which the privatized companies can be resold to state-owned companies. Previously, EdF had already acquired a 20% share of Montedison, parent company of Italy's largest IPP Edison, though this is under investigation by Italian regulatory authorities. EdF and Fiat formed a consortium called Italenergia that received permission from the EU antitrust authority to take over Montedison in August 2001. Italenergia has a 96.9% stake in Montedison and a 95.7% stake in Montedison's energy subsidiary Edison. In order to reduce its $11.9-billion debt, Italenergia unveiled a plan in October 2001 to sell the seven non-energy companies and merge the group's three energy companies with Italenergia into a new company called Edison. Edison intends to bid for power stations to be sold by Enel. Edison is Italy's second-largest electricity provider.

Another facet of liberalization is that Enel must also sell its distribution networks in Italy's large urban centers. It has already sold off many of these local grids, including the Rome network to ACEA for 568 million euros in April 2001 and the Turin network to AEM for 480 billion lira. However, local electricity companies have complained that Enel is blocking some of their access and there are several lawsuits in this regard.

In early November 2000, the European Commission approved a merger that gives Italian conglomerate

Compart SpA sole control of Falck SpA, forming the then third-largest electricity generation company in Italy. The deal also gives Compart control of Falck's subsidiary, Sondel SpA. Enel, while selling off domestic assets, has made some foreign acquisitions. In December 2000, Enel purchased CHI Energy of the United States for $170 million. In September 2001, Enel purchased Nueva Viesgo of Spain, making Enel the fifth-largest generator in Spain. Siemens and Fiat Engineering are to build a power plant in Torino worth 190 million euros. It will be a combined cycle cogeneration plant for electricity and steam with a generating capacity of 390MW. Construction is due to start in Autumn 2002 with the plant entering service in 2005.

Nuclear
Italy has four nuclear power plants, all owned by ENEL. None is in operation. In 1987, a public vote decided against the use of nuclear power. The plants have remained idle since that time, and no nuclear generation is expected in the foreseeable future. Italy has a policy leaving spent fuel to cool down for decades on site before consigning it to a permanent deep-storage center.

ENVIRONMENT

Environmental awareness has grown in Italy in recent years. Although Italy has relatively low per capita energy consumption and energy intensity levels in comparison to other OECD countries, air pollution remains a serious environmental challenge.

Because of Italy's heavy reliance on oil imports to meet its energy needs, energy security and diversification of energy sources are a top priority in Italy's energy strategy. Italy is well endowed with renewable energy resources, such as solar, biomass and geothermal, that could be captured and utilized for energy. The government's goal of doubling the country's production of energy from renewable resources by 2012 will help enable Italy to meet its growing energy demand in the 21st century in a more sustainable manner.

COUNTRY PROFILE

President: Carlo Ciampi (since 1999)
Prime Minister: Silvio Berlusconi (since June 2001)
Location/Size: Southern Europe/301,230 sq km (186,763 sq mi, slightly larger than Arizona)
Major Cities: Rome (capital), Milan, Naples, Turin, Palermo, Genoa
Languages: Italian, German (parts of Trentino-Alto Adige region are predominantly German speaking), French (small French-speaking minority in Valle d'Aosta region), Slovene (Slovene-speaking minority in the Trieste-Gorizia area)
Ethnic groups: Italian (includes small clusters of German-, French-, and Slovene-Italians in the north and Albanian-Italians and Greek-Italians in the south)
Religion: predominately Roman Catholic with mature Protestant and Jewish communities and a growing Muslim immigrant community
Population (2001E): 57.7 million
Defense (8/98): Army, 165,600; Navy, 40,000; Air Force, 63,600; Paramilitary forces, 255,700; Conscripts, 134,100

ECONOMIC OVERVIEW

Minister of Economy and Finance: Giulio Tremonti
Currency: Lira (L)
Market Exchange Rate (12/18/01): US$1=2146.5 Italian Lira
Nominal Gross Domestic Product (GDP, 2000E): $1,077 billion **(2001F):** $1,093 billion
Real GDP Growth Rate (2000E): 2.9%; **(2001F):** 1.5%
Unemployment Rate (2000E): 10.7%; **(2001F):** 10.3%
Inflation Rate (consumer prices, 2000E): 2.0%; **(2001F):** 1.8%
Major Export Products: Textiles, clothing, machinery, transportation equipment
Major Import Products: Crude oil, other fuels, machinery, transport equipment
Major Trading Partners: Germany, France, Netherlands, U.S., United Kingdom

ENERGY OVERVIEW

Minister of Productive Activities: Antonio Marzano
Proven Oil Reserves (1/1/01E): 622 million barrels
Oil Production (2000E): 145,000 barrels per day (bbl/d), of which 78,000 bbl/d is crude oil
Oil Consumption (2000E): 1.9 million bbl/d
Net Oil Imports (2000E): 1.8 million bbl/d
Crude Oil Refining Capacity (1/1/01): 2.36 million bbl/d
Natural Gas Reserves (1/1/01E): 8.1 trillion cubic feet (Tcf)
Natural Gas Production (1999E): 618 billion cubic feet
Natural Gas Consumption (1999E): 2.4 Tcf
Net Natural Gas Imports (1999E): 1.8 Tcf
Recoverable Coal Reserves (1997): 37 million short tons (Mmst)
Coal Production (1999E): 0.02 Mmst
Coal Consumption (1999E): 19.2 Mmst
Electric Generation Capacity (1999E): 65.5 million kilowatts
Electricity Generation (1999E): 247.7 billion kilowatthours
Electricity Consumption (1999E): 272.4 billion kilowatthours

ENVIRONMENTAL OVERVIEW
Minister of Environment: Altero Matteoli
Total Energy Consumption (1999E): 8.0 quadrillion Btu* (2.1% of world total energy consumption)
Energy-Related Carbon Emissions (1999E): 121.3 million metric tons of carbon (2.0% of world total carbon emissions)
Per Capita Energy Consumption (1999E): 139.7 million Btu (vs U.S. value of 355.8 million Btu)
Per Capita Carbon Emissions (1999E): 2.1 metric tons of carbon (vs U.S. value of 5.5 metric tons of carbon)
Energy Intensity (1999E): 6,457 Btu/ $1990 (vs U.S. value of 12,638 Btu/ $1990)**
Carbon Intensity (1999E): 0.09 metric tons of carbon/thousand $1990 (vs U.S. value of 0.19 metric tons/thousand $1990)**
Sectoral Share of Energy Consumption (1998E): Industrial (44.1%), Transportation (25.7%), Residential (23.6%), Commercial (6.6%)
Sectoral Share of Carbon Emissions (1998E): Industrial (41.2%), Transportation (29.8%), Residential (22.7%), Commercial (6.3%)
Fuel Share of Energy Consumption (1999E): Oil (51.1%), Natural Gas (30.5%), Coal (5.7%)
Fuel Share of Carbon Emissions (1999E): Oil (61.3%), Natural Gas (29.1%), Coal (9.6%)
Renewable Energy Consumption (1998E): 560 trillion Btu* (1% increase from 1997)
Number of People per Motor Vehicle (1998): 1.7 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Annex I country under the United Nations Framework Convention on Climate Change (ratified April 15th, 1994). Under the negotiated Kyoto Protocol (signed on April 29th, 1998, but not yet ratified), Italy, as a member of the European Union, has agreed to reduce greenhouse gases 8% below 1990 levels by the 2008-2012 commitment period.
Major Environmental Issues: Air pollution from industrial emissions such as sulfur dioxide; coastal and inland rivers polluted from industrial and agricultural effluents; acid rain damaging lakes; inadequate industrial waste treatment and disposal facilities.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol, Antarctic Treaty, Biodiversity, Climate Change, Desertification, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Tropical Timber 83, Tropical Timber 94, Wetlands and Whaling. Has signed, but not ratified: Air Pollution-Persistent Organic Pollutants.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral

shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 1999.

ENERGY INDUSTRY

Oil and Gas Company: Ente Nazionale Idrocarburi (ENI); Chief Subsidiaries: Agip (hydrocarbons exploration and production), Snam (gas supplies and hydrocarbon transportation), ENIchem (petrochemicals)
Major Pipelines (gas): TransMed, Trans-Austria Gasleitung
Major Ports: Cagliari (Sardinia), Genoa, La Spezia, Livorno, Naples, Palermo, Trieste, Venice
National Electricity Company: Ente Nazionale per l'Energia Elettrica (ENEL, undergoing privatization)

Sources for this report include: CIA World Factbook; Dow Jones; Economist; Economist Intelligence Unit; ENEL; ENI; European Union; Financial Times; La Stampa; Petroleum Economist; U.S. Commerce Department; U.S. Energy Information Administration; U.S. State Department; WEFA; World Gas Intelligence.

Links

For more information from EIA on Italy, please see:
Latest EIA Detailed Annual Data
EIA Privatization Report (oil) - Italy
EIA Privatization Report - Italy

Links to other U.S. Government sites:
CIA World Factbook, Italy
U.S. Department of Energy's Pacific Northwest Laboratories, Energy Trends, Italy
U.S. State Department's Report on Economic Policy and Trade Practices, Italy
U.S. State Department's Country Commercial Guide, Italy
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Energy Information Administration

July 2002

Caspian Sea Region: Legal Issues

CASPIAN SEA ISSUES

Questions surrounding the legal status of the Caspian Sea have hindered--but not stopped--further development of the Sea's mineral resources. Since the fall of the Soviet Union in 1991 led to the independence of three new countries bordering the Caspian, the littoral states--Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan--have been unable to agree on a legal framework governing the use and development of the Sea's oil and natural gas reserves.

The main difference of opinions among the five littoral countries lies in the uneven distribution of potential oil and natural gas riches in the region. This fact was brought to the forefront when Iranian military gunboats confronted an Azeri research vessel in the Caspian in July 2001. Although the Azeris stated that they were exploring their sector of the Caspian, the Iranians ordered the ship to vacate the area, claiming the waters where the ship was exploring remain in dispute. This military confrontation raised the stakes in the ongoing disagreement between the littoral states and highlighted the need for a legal framework on the status of the Caspian that clarifies ownership of its bountiful natural resources. From a legal perspective, the key issues include:

- Whether, in the absence of a new legal convention, treaties signed between the former Soviet Union and Iran are still in force and thereby govern current development rights. The Soviet Union and Iran signed bilateral treaties on the Caspian Sea in 1921 and 1940, but neither established seabed boundaries or discussed oil and natural gas exploration;

- The need to develop a legal framework to resolve environmental and biological issues. Several countries have opposed the laying of proposed trans-Caspian oil and gas pipelines on environmental grounds;

- Whether the Caspian is a body of water covered by the Law of the Sea Convention, which does not cover inland lakes. If the Law of the Sea convention were applied to the Caspian Sea, full maritime boundaries of the five littoral states bordering the Caspian would be established based upon an equidistant division of the sea and undersea resources into national sectors. However, if the Law of the Sea were not applied, the Caspian and its resources would be developed jointly--a division referred to as the "condominium" approach.

A working group made up of representatives from each country was created to draw up a joint declaration on the new legal status of the Caspian Sea, but the group failed to make progress on settling differences. After the working group's second meeting in December 1998, subsequent meetings were canceled in order to give participants more time to move towards common ground.

Working Toward Consensus

In the absence of a formal agreement among the five countries on the legal status of the Caspian, several countries have negotiated bilateral agreements to clarify their positions. Rather than arguing whether the Caspian is a lake or an enclosed sea and dividing the Sea accordingly, in 1997, Kazakhstan and Azerbaijan agreed "to adhere to the borders of the sectors along the median line" until a convention on the legal status of the Caspian is signed. Also in 1997, Kazakhstan signed a communiqué with Turkmenistan pledging to divide their sections of the Caspian along median lines, based upon Soviet-era divisions, until the littoral states agreed upon a new status for the Caspian.

In July 1998, Kazakhstan signed a bilateral agreement with Russia dividing the northern Caspian seabed only along median lines between the two countries, with the waters (covering issues such as shipping, fishing, and environment) remaining under joint ownership. Under this accord, Russian agreements with Iran on the division of the Caspian that date back to Soviet days would remain valid until an overall agreement is reached among all Caspian littoral states.

Former Kazakh Prime Minister Kasymzhomart Tokayev stated that Kazakhstan would consider modifying the median line on economic considerations; i.e., future hydrocarbon finds, although he insisted that within these economic zones the states would have an exclusive right to exploit natural resources. The breakthrough for Russia and Kazakhstan came after they agreed to the joint development of deposits located on the median line, including the Kurmangazy structure in Kazakhstan and the Khvalynskaya field, which is part of Lukoil's (Russia) Severny block. The understanding is that Kazakh companies can take part in Khvalynskaya, while Kurmangazy will be opened to Russian companies.

In January 2001, Azerbaijan President Heydar Aliyev and Russian President Vladimir Putin issued a joint communiqué agreeing to divide the Caspian Sea on the seabed, but keeping navigation on the entire water surface free. Under this "common water, divided sea floor" approach, the sealer could be "divided into sectors/zones among corresponding neighboring and oppositely-located states, on the principle of a median line drawn at equal distance from the sides and modified at their mutual consent."

Azerbaijan formerly had advocated for the division of the surface, water, and seabed. At the Commonwealth of Independent States (CIS) Summit in November 2001, Kazakhstan and Azerbaijan formally signed a bilateral agreement defining their sectors of the Caspian Sea. Azerbaijan and Russia are also finalizing a bilateral agreement on the Caspian Sea.

In another sign of progress towards developing a legal convention on the status of the Sea, the Caspian Working Group, comprised of the deputy foreign ministers of each of the five countries, is once again meeting regularly. At the group's session in Moscow in January 2002, the deputy foreign ministers signed a joint communiqué on the legal status of the Caspian Sea. According to Russian Presidential Special Envoy for the Caspian Sea Victor Kaluzhny, the communiqué "covers many interregional issues of five littoral states," in particular, the current political events of Azerbaijan, Iran, Kazakhstan, Turkmenistan, and Russia, as well as positions of the sides on the situation in Afghanistan.

However, the deputy foreign ministers still were not able to reach a final agreement on the Caspian. Although Kaluzhny suggested that the Caspian could receive a new legal status as early as the first half of 2002, several sticking points remain that could prevent a formal agreement. In April 2002, a long-delayed summit of the Caspian littoral heads of state failed to produce a multilateral agreement on the sea's legal status, prompting Russia and Kazakhstan to finalize their biilateral agreement.

Remaining Issues To Be Decided

Although the Caspian Sea littoral states have made progress in the working group in bringing their positions closer together, a final agreement remains out of reach. There is now general agreement between Russia, Azerbaijan, and Kazakhstan on both "the principle and the method" of dividing rights to the seabed and the mineral wealth beneath it, but Turkmenistan only agrees on the principle of dividing the Sea, and Iran disagrees with both the principle and method of dividing the Sea and its resources.

Iran's continued insistence on equal division of the Caspian Sea resources is now potentially the biggest obstacle to a formal agreement on the Caspian's legal status. In addition, although dividing the seabed would provide each country with control over its own resources, the exact location of these median lines has not been decided. Environmental concerns about the Caspian also need to be addressed.

Iran's Unwavering Stance

At the present time, Iran assumes the most isolated position among the littoral states on the division of the Sea. Iran insists that regional treaties signed in 1921 and 1940 between Iran and the former Soviet Union, which call for joint sharing of the Caspian's resources between the two countries, are valid. Iran has rejected as invalid all unilateral and bilateral agreements on the utilization of the Sea. While Iran agrees that a new legal convention is necessary, Iranian Foreign Minister Kamal Kharrazi told a meeting of deputy foreign ministers of the Caspian states in Tehran in February 2001 that the 1921 and 1940 treaties should be the basis for adopting a new legal regime.

As such, Iran is insisting that either the sea should be used in common, or its floor and water basin should be divided into equal shares. Iran's preference is for the countries around the sea to use it by consensus. Under this plan, the so-called "condominium" approach, the development of the Caspian Sea would be undertaken jointly by all of the littoral states. Iran wants all Caspian states to approve any offshore oil developments until the legal status of the Caspian Sea is agreed upon by all of the littoral countries. Another Iranian suggestion is that the littoral states should suspend all work in the Caspian Sea until the new legal status of the Caspian is determined. However, several countries are proceeding with development of subsea resources in what are generally considered to be their national waters, making the condominium approach less likely.

Iran has indicated a willingness to divide the Caspian Sea into national sectors, but only provided there is equal division of the Sea, giving each country 20% of the sea floor and surface of the Caspian. However, using the equidistant method of dividing the seabed on which Kazakhstan, Azerbaijan, and Russia have agreed, Iran would only receive about 12% to 13% of the Sea. Both Kazakhstan and Azerbaijan openly have opposed Iran's proposal to divide the Caspian into five equal sectors, stating that that does not correspond to historical traditions. Nevertheless, Iran continues to insist on receiving 20% of the Sea, and diplomats involved in the working group negotiations have said that Iran has been willing to bide its time in talks in a bid to maximize its share of the Caspian Sea.

Competing Claims and Overlapping Fields

In addition to Iran's unwavering stance are the twin problems of competing claims and overlapping fields. Central to both of these problems is where the modified median line will be drawn to demarcate national sectors. Azerbaijan, Russia, and Kazakhstan have agreed in principle on a division which would give them shares extending out from their respective coastlines. Where national zones met in the middle of the sea, borders would be equidistant from the facing coastlines.

According to diplomats involved in the working group meetings, Turkmenistan agrees in principle to dividing the seabed, but not via this method. Furthermore, the potentially difficult question about the division of oil and natural gas fields that overlap offshore boundaries has not been decided yet.

In February 1998, Azerbaijan and Turkmenistan issued a statement saying that they agreed that the Caspian Sea between Azerbaijan and Turkmenistan would be divided along a median line, but disagreements over where to draw that line caused a dispute over a field called Kyapaz by Azerbaijan and Serdar by Turkmenistan. Azerbaijan reached a preliminary agreement to develop this field in July 1998, and Turkmenistan laid claim to it by including it as part of its Block 30 licensing in September 1998.

Uncertainties over legal ownership of fields in the Caspian Sea were a contributing factor to the failure of Turkmenistan's first tender for production-sharing agreements on Turkmenistan's Caspian shelf, which included the Serdar field. Azerbaijan and Turkmenistan continue to disagree over where to draw the median lines, particularly over the Kyapaz/Serdar field. Turkmenistan repeatedly has called on Azerbaijan to halt to freeze the development of disputed deposits until the legal status of the Caspian is agreed and borders are drawn up, but in the meantime, Azerbaijan has stated that the 1970 division of the Caspian by the Soviet Ministry of Oil and Gas, which assigned the Kyapaz field to Azerbaijan, remains in force.

Turkmenistan considers that the method of dividing the Sea along a median line proposed by Azerbaijan does not take into consideration geographical peculiarities connected with the features of the shore, particularly Azerbaijan's Absheron peninsula, which juts out into the Sea. Turkmen officials say this method has led to significant deviation of the median line.

Rather, Turkmenistan wants the border line in the middle of the Sea--where its zone would meet that of Azerbaijan--to be drawn using a more approximate method, which would give it a slightly larger share of a mid-sea area where some of the best oil prospects lie. Turkmenistan wants to divide the floor along a meridian line based on the shores of the states lying opposite. Another option, according to the Turkmen side, would be for each of the Caspian states to establish a 12-mile zone along the coast. To this zone would be added a 35-mile "zone of economic interests" of each of the states, with the remaining part of the sea open for shipping by all of the Caspian states.

Disagreement between Azerbaijan and Turkmenistan over the division of the Sea has led to additional conflicts over field ownership. Turkmenistan claims that portions of the Azeri and Chirag fields--which Ashgabat calls Khazar and Osman, respectively--lie within its territorial waters. Turkmenistan has alleged that Azerbaijan is illegally working at the Khazar and Osman fields, and in July 2001, Turkmenistan demanded that Baku suspend all work at the disputed fields or "be answerable for the consequences."

In August 2001, Azerbaijan struck back, rejecting a warning that its oil exploration in a disputed part of the Caspian Sea was illegal by stating that it would not accept "any claims aimed at thwarting the realization of its sovereign rights in a sector of the Caspian Sea which belongs to Azerbaijan."

While the war of words between Azerbaijan and Turkmenistan over the Kyapaz/Serdar dispute has been highly publicized, it was superseded by another conflict over field ownership that arose between Iran and Azerbaijan in July 2001. On July 22, 2001, the Iranian Oil Ministry issued a warning to foreign energy firms about working with other states in areas of the Caspian Sea which Iran considers its territory.

The following day, tensions flared when an Iranian gunboat ordered a British Petroleum (BP) oil exploration ship, licensed to explore Azeri waters, out of what it regarded as the Iranian sector. The Geofizik-3, with BP specialists aboard, was exploring in the Araz-Alov-Sharg concession, an area 90 miles southeast of Baku, which was licensed to a BP-led consortium in 1998 by the Azeri government.

Iran disputed the legitimacy of the license, claiming that the block, which Iran calls Alborz, is in Iranian waters. BP has suspended work at the field, pending resolution of the dispute between the two countries. Although the incident was the first overt military act in the Caspian since the collapse of the Soviet Union, it was not the only disagreement between Iran and Azerbaijan. In 1999, Azerbaijan accused Iran of encroaching on what Baku considered its sector of the Caspian after Tehran reached a deal with Royal Dutch/Shell and Lasmo to carry out a seismic survey in parts of the sea.

Ecological Concerns

The Caspian Sea is home to the world's largest sturgeon population, which produces caviar. The economic importance of the region's caviar industry has united the littoral states in their concern over the environmental risks of oil and gas development in the Caspian Sea. Thus, after a number of regional environmental agreements were signed in the aftermath of the Soviet collapse, in May 1998 the Caspian Sea littoral states established the Caspian Environment Programme (CEP) in Baku. The CEP is responsible for coordinating the joint protection and management of the Caspian environment and its resources by the Caspian States.

Russia has suggested that the CEP should keep tight control over the implementation of all projects which might lead to a deterioration in the ecological situation in the Caspian. As such, Russia and Iran have stated their opposition to the laying of trans-Caspian pipelines until a legal framework is established to govern environmental and biological issues, and to establish legal responsibility for safe use of the Caspian Sea. Kazakhstan also has stated that cooperation on the environment, fishing, and navigation in the Caspian Sea would be beneficial.

IRANIAN EMBARGO AND SANCTIONS

After U.S. oil company Conoco signed an agreement with Tehran in 1995 to develop Iran's Sirri field, then-U.S. President Bill Clinton issued three executive orders that together established a total embargo on U.S.-Iran trade. They were intended to respond to Iran's support of international terrorism, efforts to undermine the Middle East peace process, and acquisition of weapons of mass destruction and the means to deliver them, a three-fold objective that remains the rationale for U.S. sanctions today.

The first executive order prohibits U.S. companies--but not their foreign subsidiaries--from supervising, managing, or financing projects relating to the development of Iran's oil and gas resources. A second executive order, issued on May 6, 1995, established comprehensive economic sanctions on Iran, again applicable to U.S. companies but not their offshore subsidiaries. Under this order, U.S. citizens may not trade in Iranian oil, finance, broker, approve or facilitate such trading, or finance or supply goods or technology that would benefit the Iranian petroleum sector.

Finally, in August 1997, President Clinton issued a third executive order that closed loopholes in the embargo whereby goods were being exported to Iran from third countries. Following President Clinton's executive orders, Conoco was forced to pull out of the Sirri project, which went to France's TotalFinaElf.

Iran and Libya Sanctions Act

Notwithstanding comprehensive unilateral sanctions against Iran and Libya (which date to 1986), the Iran and Libya Sanctions Act (ILSA) was enacted by Congress in August 1996. ILSA had many of the same objectives as the unilateral sanctions, but is different in jurisdictional scope. Unlike the embargoes against Iran and Libya, which are primary sanctions, ILSA imposes a secondary boycott. The legislation was designed essentially to force foreign companies into choosing to do business with Iran and Libya or the United States.

ILSA mandates the U.S. president to impose sanctions on any U.S. or foreign person who, after August 5, 1997, invests $20 million or more in an Iranian project ($40 million for Libya; this was lowered to $20 million in August 2001), if the investment directly and significantly contributes to the enhancement of Iran's or Libya's ability to explore for, extract, refine, or transport by pipeline its oil and natural gas reserves. ILSA requires that sanctions be imposed for a minimum of two years.

These prohibitions in ILSA, as well as the executive orders, would likely apply to any joint-use arrangements in the Caspian Sea, including the Iranian sector of the Caspian Sea. The U.S. has opposed large-scale oil swaps with Iran by U.S. companies. However, ILSA does not prohibit foreign companies from trading in Iranian crude oil and gas commodities, and in 1997, the U.S. State Department decided that proposed exports of natural gas from Turkmenistan to Turkey via Iran did not technically violate U.S. law.

Although ILSA initially may have had some effect in deterring investment by companies that did not wish to risk sanctions, the law has never been enforced. At the first test of the law, when France's TotalFinaElf, Russia's Gazprom, and Petronas (Malaysia) signed a $2-billion agreement to develop Iran's South Pars field, the Clinton Administration granted a waiver to the companies in order to avoid clashes with its European allies. The Clinton Administration chose not to pursue several other potential violations, and in recent years ENI (Italy), Royal Dutch/Shell, TotalFinaElf, and BP have agreed to large projects in Iran without reprisal from the U.S.

On August 3, 2001, President George W. Bush signed legislation extending ILSA for an additional five years. In a statement issued by the White House press office that day, President Bush said that he approved of provisions added to the ILSA legislation that call for frequent review of sanctions to assess their "effectiveness and continued suitability."

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Caspian Sea Region: Environmental Issues

Introduction

As the meeting point of the Middle East, Europe, and Asia, the Caspian Sea is home to cold, continental deserts and semi-deserts in the north and east, as well as warmer mountain and highland systems in the southwest and south. The coastal wetlands of the Caspian include many shallow, saline pools, which attract a variety of birdlife and biodiversity--over 400 species are unique to the Caspian. As the largest inland body of water on earth, the Caspian Sea, which is surrounded by Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan, is also home to the famous *osyetr*--the Russian term for sturgeon--which produce the eggs necessary for the caviar industry.

Although oil production and development have taken place in present-day Azerbaijan for more than 100 years, the dissolution of the Soviet Union, along with the discovery of significant new oil and gas reserves in the Caspian region, led to heightened interest (including concern for the environment) in the region. While the economic decline that accompanied the breakup of the Soviet Union has reduced industrial production in the region (and the resultant flow of contaminants into the Caspian), years of neglect have left the sea in a precarious position environmentally.

Untreated waste from the Volga River, into which half the population of Russia--and most of its heavy industry--drains its sewage, empties directly into the Caspian Sea. Oil extraction and refining complexes in Baku and Sumgayit in Azerbaijan are major sources of land-based pollution, and offshore oil fields, refineries, and petrochemical plants have generated large quantities of toxic waste, run-off, and oil spills. In addition, radioactive solid and liquid waste deposits near the Gurevskaya nuclear power plant in Kazakhstan are polluting the Caspian as well.

As economic activity in the region rebounds, previous discharge and non-point source contamination levels can be expected to resume, further polluting the sea and endangering the region's inhabitants. The impact on human health has been measurable, and the Caspian's sturgeon catch has decreased dramatically in recent years, from 30,000 tons in 1985 to 13,300 tons in 1990 and then to as low as 2,100 tons in 1994. Thus, there is an urgent need to address contamination of the Caspian environment by heavy industry, agriculture, oil production, and power generation.

Oil Pollution and Other Environmental Problems

The collapse of the Soviet Union exposed the regime's poor environmental record in the Caspian. Rusty derricks, poisoned soil and water, pools of oil scum, and well fires that burned for years were byproducts of the Soviets' oil exploitation in the Caspian region, and many Soviet-era wells remain in place. Although the new oil rush is more sensitive to environmental issues--in this regard, the involvement of Western companies using more up-to-date technology might actually lead to a small environmental *improvement*--the long history of contamination, combined with short-term economic pressures to exploit the sea's potential, will mean that threats to the Caspian

environment will continue to loom large.

Industry, oil production, and transportation have been the source of severe air, water, and soil pollution in the Caspian region. Systematic water sampling in different parts of the Caspian Basin show contamination from phenols, oil products, and other sources. Mineral deposit exploration, particularly oil extraction and pipeline construction, have contributed to the pollution of about 30,000 hectares of land.

The most acute soil degradation problems are on the Absheron Peninsula in Azerbaijan, where a century's worth of oil production has left the land heavily contaminated. Scant environmental consideration was given to industrial and energy development in Azerbaijan, with disastrous consequences: oil production has left behind vast areas of wasteland, with standing oil ponds and severely contaminated soil, a shore along Baku Bay that is black with oil residue, and high levels of pollution in the Caspian Sea.

Although the decline in industrial and agricultural output has reduced air pollution and discharges into the Caspian, pollution from oil fields, refineries, and power plants continues at high rates due to the use of outdated technology malfunctioning equipment. However, Azerbaijan is becoming more concerned with environmental issues. In September 1998, representatives of SOCAR, the Azeri state-run oil industry, observed an oil spill exercise conducted by Briggs Marine Environmental Services, which has agreed to train crews from Azerbaijan on the use of oil spill response measures. In addition, World Bank representatives have met with officials in Baku to launch an emergency Environmental Investment Project.

While Azerbaijan has been hardest hit by pollution from oil exploitation, other littoral and neighboring states also have been adversely affected. In Kazakhstan, environmental tests conducted recently noted that cases of blood disease, tuberculosis, and other diseases are four times more common in the Caspian area than on average in Kazakhstan. Although the tests showed that the environmental contamination in the northeast Caspian is less than what has been recorded previously, water which has been contaminated by oil products in Kazakhstan is still used for drinking water. This contamination is cited as a main reason for intestinal infections in Kazakhstan's coastal areas.

In response, Prime Minister Nurlan Balgimbayev of Kazakhstan has stated that all foreign companies interested in the Caspian Sea must be ready to meet guidelines on environmental safety. The European Bank of Reconstruction and Development (EBRD) is offering technical aid for estimating the environmental impact of oil and gas development projects.

Oil Transport Issues

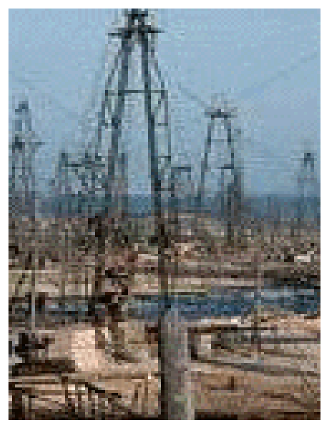
In addition to the health and environmental threats due to oil production in the Caspian, the sea's geographic location complicates the issue. Because the Caspian is land-locked, in order to reach world markets all oil produced there has to be transported via pipeline, which increases the environmental risks. Illegal tapping of the Baku-Novorossiisk pipeline in Chechnya already has caused major leakage problems.

Environmental questions surrounding the Bosporus in particular and the Black Sea in general have also begun to factor heavily in the choice of export routes for Caspian oil. Turkey has argued against export routes that utilize the Black Sea because the projected increase in large oil tankers would pose serious navigational, safety, and environmental threats to the Bosporus.

In addition, the northern Caspian is home to more the 80% of the Caspian's netted fish, and is characterized by relatively shallow waters and the lack of currents, making it more difficult to regenerate its natural resources in the event of an environmental problem. Tanker traffic and trans-Caspian pipelines potentially could impact fish migration routes.

Waste Discharges

Approximately 130 large and small rivers flow into the Caspian, nearly all of which flow into the north or west coast. The Volga River, the sea's largest single source, splits into a thousand smaller streams as it flows through a largely uninhabited delta feeding into the Caspian Sea. This marsh serves as a filter, cleansing the river of some of the upstream pollution, but sufficient amounts still reach the Caspian to cause major imbalances, especially in the shallow north basin which has limited absorption capacity.



The Caspian still has miles of undeveloped coastline, especially along the eastern shore in Kazakhstan and Turkmenistan where there are no permanent inflows. Yet the south end of the sea is a deep, dark gray, polluted with the discharges from sewer pipes and factory drains from the five littoral states. Air pollution from Tehran, due largely to the abundance of old cars that lack catalytic converters, falls out in the Caspian when the wind blows the smog north from Iran, contributing to the sea's environmental problem.

However, waste discharges--both from industrial sources such as oil operations and mining and municipal sewage--account for the lion's share of pollution in the Caspian. The World Bank has estimated that a million cubic meters of untreated industrial wastewater is discharged into the Caspian annually. A major culprit is the Azeri coastal city of Sumgayit: during the Soviet era, the city was planned as a model center for petrochemical industries, but in an effort to keep up with the continually increasing production quotas, the environment was subjugated to industrial goals. Hundreds of thousands of tons of toxic wastes each year were released into the atmosphere or dumped into a creek that fed into the Caspian.

The result was predictable: pollution overwhelmed the sea around Sumgayit and Baku, creating a virtual dead zone, and the area witnessed a dramatic rise in stillbirths and miscarriages. The legacy lives on, as untreated sewage is still dumped into the Caspian, and mercury-contaminated sludge wastes (from the use of mercury in chlor-alkali production) are accumulating. Because the wastes often are stored inadequately, ground water contamination and leakage into the Caspian Sea is likely. Discharges of processed water already have severely contaminated sea bottom sediments in the Caspian.

Scientists have expressed concern that new offshore drilling could discharge harmful pollutants into the sea. Muftakh Diarov, director of the Research Center for Regional Environmental Problems, stated that "pollution of the Caspian Sea from waste waters containing high concentrations of dangerous substances used at the Sunkar drilling barge has been occurring since the first day of operations." Diarov said analysis of the waste water, carried out at the laboratory of the Atyrau region's division of the Environmental Protection Agency, showed that it contained concentrations 180 times higher than acceptable for ammonia salts, 188 times higher for nitrates, and 220 times higher for phenols.

Sea Rise

In addition to the man-made pollution that has adversely affected the Caspian, the sea has exhibited a curious natural variation in its water level that has created more environmental problems and wrought havoc on coastal infrastructure. Since 1978, the sea level has risen almost 7.5 feet--flooding in coastal zones has inundated residential areas, transport, telecommunications and energy infrastructure, chemical and petrochemical industries, croplands and hatcheries, forcing thousands of residents to be evacuated from flooded homes. In Turkmenistan, the town of Dervish, which is detached from the western part of the mainland, is turning into an island due to the rise in sea level, and Cheleken and Karakul are sinking into the water as well.

Gradual flooding has precipitated abrasive erosion of sea shelves, endangering oil infrastructure, and the rising seawater threatens to flood oil wells along the coast and cause spills directly into the sea. In addition to the danger posed to oil fields in Kazakhstan and Azerbaijan, the sea-level rise results in changes in water regime, hydrochemical regime of river mouths, dynamics and chemical composition of groundwater, structure and productivity of biological communities in the littoral and in river mouths, sediment deposition patterns, pollution by heavy metals, petroleum products, synthetic substances, radioactive isotopes, and other substances. Up to 100,000 people in coastal cities and towns in Azerbaijan alone have been affected by the spread of toxic wastes, contamination of water supplies, and the loss of infrastructure.

The sea's rise has confounded scientists and engineers who have monitored the sea level. From 1933-1941, experts recorded that the Caspian's water level consistently *decreased*, by a total of 5.5 feet. The pattern of sea level increase since 1978 has played havoc with engineers who have attempted to deal with the natural water variation. For example, at the beginning of the 20th century, the strait between the Garabogazkol Gulf in Turkmenistan and the Caspian allowed for significant water flow to the smaller basin. As the sea level fell in the mid-20th century, the flow

consistently decreased. In March 1980, Soviet engineers constructed a solid dam across the Strait to stem any further drop in sea level.

However, the average sea level had already begun to increase in 1978, and by September 1984 planners were forced to open a spillway in the dam to permit some discharge of water in the Gulf. The dam also created other environmental problems: in addition to barring sturgeon from their spawning grounds, the dam dried up what had been a stable salt lagoon. The result was salt-laden dust storms that turned surrounding towns and villages into ghost towns. Desertification and other environmental damage accelerated until the dam was finally demolished in June 1992. This example highlights the difficulty in anticipating natural variations in the hydrologic cycle and creating engineering works to counter this natural variability effectively.

Environmental Legislation and Regulation

Complicating these environmental problems is the dispute surrounding the legal rights to the Caspian's resources. The argument among the littoral states over a method for dividing the Caspian still has not been resolved. Negotiations on legal issues surrounding the Caspian Sea include the resolution of environmental concerns. Both Iran and Russia have opposed the laying of trans-Caspian pipelines and objected to oil and gas development projects in the Caspian on environmental grounds. Russian parliamentary hearings on the final status of the Caspian Sea called for accelerating the signing of the Agreement on Preservation and Rational Use of Caspian Sea Bio-Resources, and for creating more stringent protection of the Caspian.

Following talks about the division of the northern Caspian between Kazakhstan and Russia, Russia called for uniform environmental requirements to be applied in the area along Russian policies, while noting that the agreement stated that the Caspian's water is an asset of both countries. However, companies involved in exploration and drilling in the Caspian shelf have complained of overlapping environmental authorities, conflicting regulation between local and national authorities, and the lack of specific environmental regulations that are required in environmental laws. In Azerbaijan, for example, the country's Energy Law appears to be in direct contradiction to its Subsoil Law.

In Kazakhstan, the fear of losing the country's competitive edge and scaring off investors has made the government reluctant to issue regulations endorsing more rigorous environmental standards, according to Muftakh Diarov, director of the Research Center for Regional Environmental Problems. In addition, Diarov asserts, Kazakhstan has not adopted more stringent environmental standards because currents in the Caspian transport pollution from the Caspian shelf into Russian waters.

Although governments have not always been diligent in their implementation or enforcement of environmental legislation and regulation, environmental groups are finding more success. Environmental concerns have meant that companies are increasing their use of environmental insurance. The Offshore Kazakhstan International Operating Company (OKIOC), which has begun drilling, has already signed a contract for a $500 million environmental insurance policy from a Kazakh company, which then obtained reinsurance from a Western insurer. In turn, Kazakhstan's parliament now is considering draft legislation requiring oil investors to insure their projects against environmental risks, and the country's Deputy Minister of Natural Resources has criticized the OKIOC, saying its environmental insurance coverage should be much higher.

The Caspian Sea in the 21st Century

In light of the economic situation in countries of the Caspian region, the environmental outlook for the Caspian Sea is not favorable. The lack of state revenue in each country means that environmental cleanup will start late and likely will not be a government priority.

However, the spotlight on the sea's resources also has brought attention to the plight of its environmental health. As environmental awareness grows in the region, there will be more pressure to develop the oil and gas in an environmentally sensitive way. Lacking adequate financial resources, governments in the region already are shifting responsibility for cleanup efforts to foreign oil and gas companies or to international development banks. The World Bank approved an urgent environmental investment project in Azerbaijan in 1998, earmarking $25 million to build a sturgeon hatchery safely above the Caspian Sea flood plain, clean-up mercury contamination at Sumgayit, and construct a new landfill. In addition, the funding has helped finance several pilot projects to determine the most cost-effective treatment method for onshore oil field cleanup of oil-contaminated sediments and sludges.

Although the World Bank's investment project sought to integrate effectively environmental management practices into Azerbaijan's post-Soviet economy, Azerbaijan's current level of environmental expenditures, despite projected growth in GDP and government revenues, remains inadequate to address the major environmental problems in the country. The same could be said for the four other littoral states--where the will to push forward with stricter environmental policies has been in place, the means to implement them has not followed suit.

CASPIAN
ENVIRONMENT PROGRAMME

An encouraging sign has been a move towards greater cooperation in protecting the Caspian. Several initiatives have boosted regional cooperation in protecting the environment, including the establishment of the Caspian Environment Programme (CEP) in conjunction with the Global Environmental Facility. The overall goal of the CEP is defined as "environmentally sustainable development and management of the Caspian environment, including living resources and water quality, so as to obtain the utmost long-term benefits for the human populations of the region, while protecting human health, ecological

integrity, and the region's sustainability for future generations."

Implementation of these goals will be extremely difficult, especially in light of the region's economic situation. Realistically, the challenge will be to find the right balance between developing the Caspian's bountiful oil and gas resources and protecting the sea, marine life, and the health of the region's inhabitants, all in a cost-effective manner.

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May 2002

Central Asia: Turkmenistan Energy Sector

TURKMENISTAN

Following several years of decline after Turkmenistan's independence from the Soviet Union in 1991, Turkmenistan's economy has rebounded in the past four years. Turkmenistan, whose economy relies heavily on oil and natural gas production, suffered a 25.9% drop in its real gross domestic product (GDP) in 1997 when Russia closed off its natural gas pipeline network--Turkmenistan's sole natural gas export option at the time. Since the resolution of the dispute with Russia, Turkmenistan's natural gas exports have increased dramatically, spurring the country's economy to three straight years of double-digit real GDP growth, including an 18% increase in 2001. Turkmenistan's economy is forecast to grow an additional 13% in 2002.

Nevertheless, Turkmenistan's real GDP in 2001 was still only 70% of its 1990 level, and economic and political reform have been stifled under the autocratic leadership of President Saparmurat Niyazov, a former communist who has ruled Turkmenistan since independence and was named president for life in 1999. The country's unemployment rate, although down to 14% in 2001 from a high of 24.2% in 1998, is still problematic, and foreign direct investment, over 90% of which flows into the country's oil and natural gas sectors, has slowed over the past few years because of the restrictive conditions that Turkmenistan attaches to foreign investment. Privatization goals remain limited, and the country has not taken steps to diversify its economy to reduce its dependence on natural resource exports.

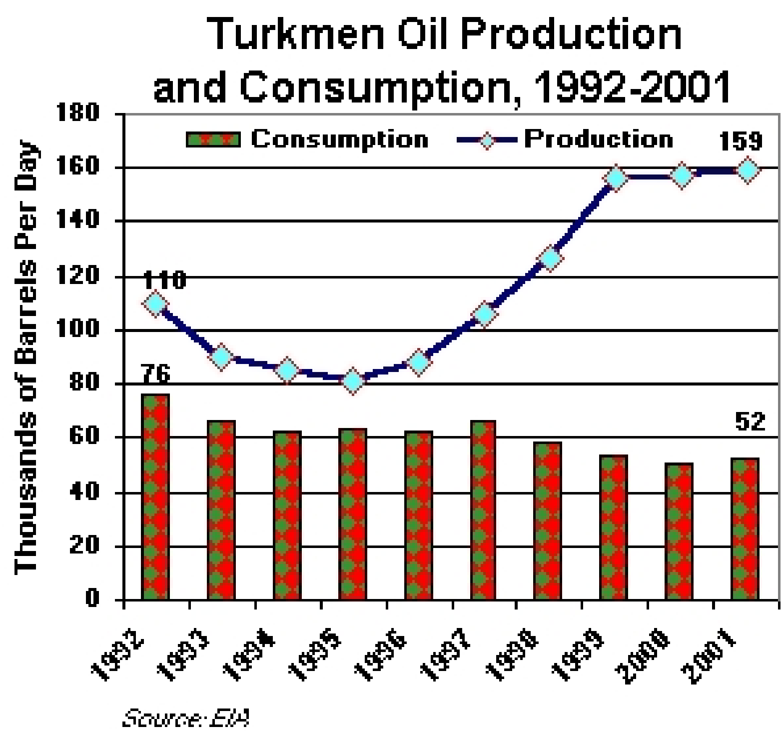
Oil

Turkmenistan has 546 million barrels in proven oil reserves, with possible reserves (mainly in the western part of the country and in undeveloped offshore areas in the Caspian Sea) of up to 1.7 billion barrels. The country's oil production, which steadily declined after independence, from 110,000 barrels per day (bbl/d) in 1992 to 81,000 bbl/d in 1995, has increased dramatically in the past six years, reaching 156,400 bbl/d in 1999 before leveling off in the past two years. In 2001, Turkmenistan produced 159,000 bbl/d of oil while consuming 52,000 bbl/d. Turkmenneft, the state oil company, produced approximately 90% of this total, with the remainder coming from the state natural gas company, Turkmengaz, and several foreign oil companies operating under PSAs in Turkmenistan.

In 2002, Turkmenistan is seeking to increase its oil output to 200,000 bbl/d, with additional production to come from newly developed wells in the western part of the country. Under a 10-year program dictated by President Niyazov, Turkmenistan aims to raise its oil production to nearly 1 million bbl/d by 2010. According to Turmenistan's Oil and Gas Industry and Natural Resource Minister, Kurbannazar Nazarov, Turkmenistan needs $25 billion in foreign investment to its oil and natural gas sectors between now and 2010. In an effort to create a better business climate to attract foreign investment, in June 1998 Turkmenistan restructured its oil and gas industries into several state-owned companies.

Although the country has attempted to ease restrictions on foreign investment, many layers of regulation remain in place. Turkmenistan maintains prohibitive rules that prevent companies using subsurface resources to export hydrocarbons. Since foreign investors do not have access to export pipelines (state-run Turkmenneft, Turkmengaz, and Turkmenneftegaz, the oil and natural gas marketing company, currently own all of the country's pipelines), they are forced to sell the oil and natural gas they produce in Turkmenistan through the state commodities exchange or send it to refineries. Oil and natural gas are sold in Turkmenistan at fixed prices that are well below world market levels.

As a result, several projects that could substantially increase Turkmenistan's oil production have stalled. Petronas (Malaysia), which is developing the Cheleken-1 oil and natural gas deposit under a PSA signed in 1996, suspended operations for more than a year, since the company determined it could not develop the field profitably under Turkmenistan's export restrictions. Swap arrangements, such as United Arab Emirate-based Dragon Oil's small-scale swap agreement with Iran, have proved modestly successful, but the Turkmen government has pledged to work on legislation that will expand the opportunities for foreign investors to export oil and natural gas, including liberalizing pipeline transport and easing the tax burden.



Downstream/Refining

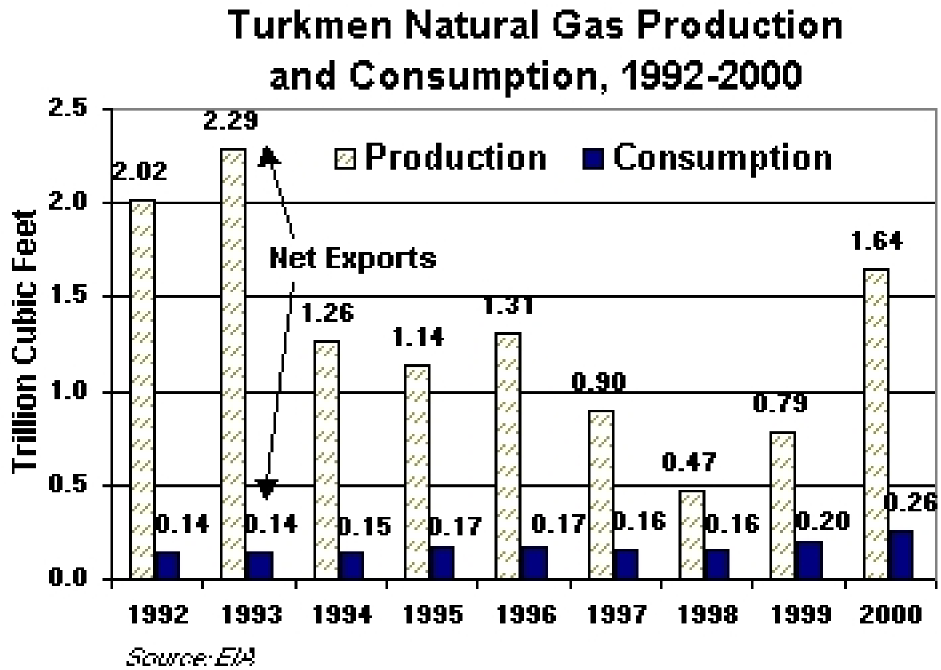
Turkmenistan has two refineries, the 116,500-bbl/d refinery at Turkmenbashy and a 120,500-bbl/d refinery at Seidi. Both facilities are slated for modernization and expansion to meet the country's expected increases in oil production and demand, and Turkmen President Saparmurat Niyazov is planning to call a tender in 2002 to build a new 100,000-bbl/d refinery. Work is underway on a $1.4-billion upgrade and modernization of the Turkmenbashy refinery, with financing from German and Japanese sources.

As part of the modernization, which is scheduled for completion in 2004, France's Technip was awarded a contract to build a lubricants blending plant. In April 2001, the catalytic cracking unit was launched by Technip and Iranian NINISC at a cost of $300 million. The unit, with a capacity of 36,150 bbl/d, is designed to produce high-octane gasoline, diesel, heating oil, and liquefied petroleum gas. Complete reconstruction of the refinery will give Turkmenistan the ability to produce motor oil, lubricants, and polymers to world standards, allowing the country to cease importing lubricating oils.

Natural Gas

Turkmenistan has some of the world's largest deposits of natural gas, with proven natural gas reserves of approximately 101 trillion cubic feet (Tcf). The largest natural gas fields are in the Amu-Dar'ya basin, with perhaps half of the country's natural gas reserves located in the giant Dauletabad-Donmez field. In addition to Amu-Dar'ya, Turkmenistan contains large natural gas reserves in the Murgab basin, particularly the giant Yashlar deposit, which contains an estimated 27 Tcf. During the last 10 years, Turkmenistan also has discovered 17 new natural gas deposits in the Lebansky, Maryinsky, and Deashoguzsky regions of the country.

Turkmenistan was a substantial natural gas producer under the Soviet Union, but after the country became independent, Turkmen natural gas became a competitor with Russian natural gas. Since Turkmenistan's only natural gas export routes ran through Russia, Gazprom limited Turkmen natural gas exports, and as a result Turkmenistan's natural gas production sagged throughout the 1990's. Following the resolution of a pricing dispute with Russia in 1998 and the construction of an export pipeline to Iran, Turkmenistan's natural gas production began to climb steadily. In 2001, the country's natural gas production jumped to 1.64 Tcf against consumption of just 0.26 Tcf. Turkmengaz produced 85% of this total, with Turkmenneft accounting for the remaining 15%.



With its large natural gas reserves, Turkmenistan is counting on increased natural gas production and exports to fuel its economic recovery. In May 2001, Turkmengaz started exploration and prospecting work on a new field in Darganata, northeastern Turkmenistan. Commercial exploitation of the Gagarinskoye deposit in Zaunguz Karakum is scheduled to begin soon, while resumption of work in the Samantepe field on the right bank of Amu Dar'ya in eastern Turkmenistan is planned. Under a presidential program, Turkmengaz also is stepping up exploratory work in the Karakum and Kyzylkum deserts. Through the first two months of 2002, Turkmenistan already had produced 413 billion cubic feet (Bcf) of natural gas.

In order to reach its full natural gas production potential, however, Turkmenistan must solve the problem of getting its natural gas to consumers, as well as getting paid in hard currency. The country has been unable to capitalize on its natural gas resources because it lacks pipeline outlets to world markets. As a result, Turkmenistan is forced to sell its natural gas to ex-Soviet states that either cannot pay fully in cash or are tardy with payments for supplies already received; both Azerbaijan and Kazakhstan are indebted to Turkmenistan for natural gas supplies. In October 2000, Turkmenistan agreed to resume the export of natural gas supplies to Ukraine that had been suspended in May 1999 because of Ukraine's $281-million natural gas debt.

In a bid to secure a market for its natural gas, on May 14, 2001, Turkmenistan agreed with Ukraine on a major natural gas export deal. Under terms of the deal, Turkmenistan will provide Ukraine with 8.83 Tcf of natural gas between 2002 and 2006. Turkmenistan will sell Ukraine 1.41 Tcf of natural gas in 2002 and 1.77 Tcf in 2003, with remaining deliveries to be agreed later. Turkmen officials signed the deal on the condition that Ukraine makes timely payments for supplies. Ukrainian officials agreed to pay for the Turkmen natural gas 60% in cash, with the remainder paid for through participation in 20 construction and industrial projects in Turkmenistan worth a total of $412 million.

Coal

Turkmenistan has no coal reserves, nor any coal production. Although the country consumed a minimal amount of coal during the Soviet era, in the aftermath of the collapse of the Soviet Union, Turkmenistan rapidly phased out its coal use, and the country's consumption fell from 551,000 short tons in 1992 to zero in 1998.

Electricity
With 3.9 gigawatts (GW) of installed capacity, 99% of which is thermal, Turkmenistan has sufficient electricity-generating potential to power its own cities, unlike much of Central Asia. In 2000, Turkmenistan's power sector generated 9.3 billion kilowatt-hours (Bkwh) while Turkmen consumers used just 7.7 Bkwh, giving the country 1.6 Bkwh in surplus electricity. However, owing to the country's inefficient, Soviet-era power infrastructure that is in need of repair, power line losses wasted a significant portion of the electricity Turkmenistan generated in 2000, resulting in exports of only 0.9 Bkwh.

Most of the electricity that Turkmenistan exports is sent to southwestern Kazakhstan and northeastern Afghanistan, although Armenia, Turkmenistan, and Iran have discussed greater cooperation in the energy sphere. A power transmission line connecting Turkmenistan to northern Iran would allow Turkmen electricity exports to Iran and to Armenia, since Armenia and Iran's electricity grids are connected.

Return to Central Asia Regional Analysis Brief

June 2002

Azerbaijan

Since becoming independent in 1991, Azerbaijan has attracted significant international interest in its substantial oil and natural gas reserves. Foreign investors are helping the country to develop its rich oil and natural gas reserves in the Caspian Sea basin, and construction of new pipelines may allow Azerbaijan to become a significant energy exporter in the next decade.

Note: Information contained in this report is the best available as of June 2002 and is subject to change.

GENERAL BACKGROUND

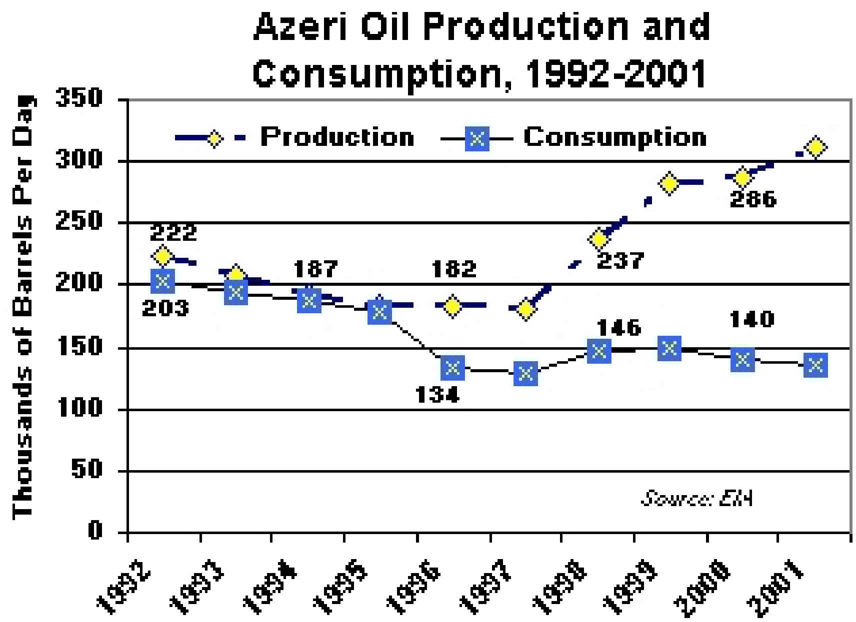
Azerbaijan received its independence from the Soviet Union in 1991, but the country continues to face considerable problems in making the transition from a command to a market economy, including the loss of its traditional markets, the need to diversify its economy, excessive bureaucratic regulation, and the slow pace of structural reform. Fighting broke out between Azerbaijan and Armenia in 1988 over Nagorno-Karabakh, an Azerbaijani enclave that is largely Armenian populated. A ceasefire was declared in 1994, one year after Azerbaijani President Heydar Aliyev took power in a bloodless coup, but Azerbaijan lost almost 20% of its territory and has been forced to support some 750,000 displaced Azeris.

As a result of the conflict, Azerbaijan implemented an economic blockade of both Nagorno-Karabakh and Armenia, which is still in effect. In 1992, the United States passed Section 907 of the Freedom Support Act, restricting U.S. government assistance to Azerbaijan until Azerbaijan takes "demonstrable steps to cease all blockades and other offensive uses of force against Armenia and Nagorno-Karabakh." In January 2002, U.S. President George W. Bush granted Azerbaijan a waiver on Section 907 due to the country's support for the U.S.-led war on terrorism.

Azerbaijan's real gross domestic product (GDP) contracted by almost 60% from 1990 to 1995, but the country began a period of steady growth in the latter half of the decade, fueled by foreign investment in the country's bountiful oil and natural gas sectors. The oil industry currently accounts for 70% to 80% of total foreign investment in Azerbaijan, and foreign direct investment increased from $15 million in 1993 to $827 million in 1999, about 20% of Azerbaijan's GDP. Azerbaijan's posted its fifth straight year of economic growth in 2001, with a real GDP increase of 5.2%. Azerbaijan's real GDP is forecast to increase another 5.7% in 2002, but even with this steady growth and continued foreign investment, Azerbaijan's GDP is not expected to reach its 1991 level until 2007.

Azerbaijan's hope for future economic growth rests with successful development of its vast oil and natural gas resources in the Caspian Sea region. Crude oil and oil product exports make up over 70% of Azerbaijan's exports, and oil-related revenue makes up nearly 50% of budget revenues. On December 29, 1999, President Aliyev issued a decree creating a State Oil Fund designed to use money obtained from oil-related foreign investment on education, reducing poverty, and raising the living standards of the rural population in Azerbaijan. In 2002, the State Oil Fund is expecting to take in $185 million. However, the unresolved Nagorno-Karabakh conflict remains an obstacle to economic progress, and the country still faces several years of tight finances, as Azerbaijan's oil revenues are likely to remain limited until 2005.

OIL



Azerbaijan is one of the world's oldest oil-producing countries. The country's oil industry experienced a boom at the beginning of the 20th century, and during World War II, the Azerbaijani Soviet Republic produced approximately 500,000 barrels per day (bbl/d). However, oil production in Azerbaijan dropped off dramatically in the post-war years as the Soviet Union directed resources for energy development elsewhere. In addition, due to extensive oil development combined with a lack of environmental protection measures, Azerbaijan's coastline and the Caspian Sea suffered heavy environmental damage during the Soviet era.

Following Azerbaijan's independence in 1991, the country's oil production continued to decline, falling to just 180,000 bbl/d in 1997. Yet, with Azerbaijan's 1.2 billion barrels of proven oil reserves, as well as enormous possible reserves in undeveloped offshore Caspian fields, international investors and multinational energy companies began flocking to independent Azerbaijan in the early 1990's, looking to tap the country's huge hydrocarbon wealth. Since 1996, over $4 billion has been invested in the country's oil sector, and Natik Aliyev, president of the State Oil Company of the Azerbaijani Republic (SOCAR), has stated that he expects investment in the country's oil sector to surpass $60 billion.

As a result of the large amount of foreign investment in Azerbaijan's oil sector, the decline in the country's oil production has been halted, and in 1998 the trend was reversed. In 2001, Azerbaijan posted its fourth consecutive annual increase in its average oil production, as output rose to 311,200 bbl/d. Preliminary EIA data shows that Azerbaijan's oil production has remained stable in 2002, averaging 310,200 bbl/d through March.

Over 80% of Azerbaijan's oil production currently comes from offshore, with a significant percentage coming from the shallow-water section of the Gunashli field, located 60 miles off the Azeri coast. Development of new fields through joint ventures (JVs) and production sharing agreements (PSAs) in the Caspian Sea likely will boost Azerbaijan's oil production well beyond its earlier peak, with predictions that Azerbaijani oil exports could exceed 1 million bbl/d by 2010 and 2 million bbl/d within 20 years.

To date, Azerbaijan has signed 21 major field agreements with 33 companies from 15 countries. However, not all of these projects have been successful, with several projects announcing disappointing drilling results and several JVs and PSAs shutting down, including the Caspian International Petroleum Company and the North Absheron Operating Company. In addition, restrictions on the ability of JVs to export their oil directly has contributed to a lack of development at some fields. To spur increased development, Azerbaijan decided to abolish JVs and convert them to PSAs in 2000.

Oil production from the country's first PSA, with the Azerbaijan International Operating Company (AIOC), began in November 1997. In September 1994, in what was described as "the deal of the century," AIOC, an international consortium made up of 10 energy companies, signed an $8 billion, 30-year contract to develop three fields (Azeri, Chirag, and the deepwater portions of Gunashli, ACG) with total reserves estimated at 4.3 billion barrels of oil. Almost all of Azerbaijan's oil production increases since 1997 have come from AIOC, which is operated by BP (U.K.). From November 1997 through the end of 2001, AIOC had produced a total of 133.5 million barrels of oil, mostly from the Chirag-1 stationary platform. In the first four months of 2002, AIOC produced 1.98 million tons of oil (an average of 120,000 bbl/d) from ACG deposits, with plans to increase output to 130,000 bbl/d by the end of 2002.

Azerbaijan's big production surge in the next decade is expected to come from further development of ACG. In August 2001, AIOC and Azeri government officials signed an agreement to carry out an expansion at ACG. The cost of the expansion plans, called Phase One, is estimated at $3.3 billion. Phase One envisages the construction of a drilling platform for 48 wells, a natural gas compressing facility, an underwater pipeline from the Azeri field, and modernization of an onshore oil terminal. AIOC production is slated to increase to 400,000 bbl/d by 2004 with the full implementation of Phase One plans.

Caspian Issues

Continued uncertainty over the Caspian Sea's legal status is hindering further oil and natural gas development in the area. The Caspian Sea littoral states--Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan--thus far have failed to agree on a plan to divide up the sea's resources, including the oil-rich seabed. Azerbaijan, along with Russia, and Kazakhstan, has advocated the establishment of maritime boundaries based on an equidistant division of the sea, but Iran and Turkmenistan disagree.

Azerbaijan remains locked in disputes with Turkmenistan and Iran over competing claims to overlapping fields. Turkmenistan and Azerbaijan have traded harsh words over the Kyapaz-Serdar, Khazar, and Osman fields, while Azerbaijan has objected to Iran's decision to award Royal Dutch/Shell and Lasmo a license to conduct seismic surveys in a region that Azerbaijan considers to fall in its territory. In July 2001, tensions flared in the South Caspian when a British Petroleum (BP) ship, licensed to explore Azerbaijan's Araz, Alov, and Sharg concession, was ordered to leave the area by an Iranian gunboat, since Iran considers the area, which it calls Alborz, to be a part of the Iranian sector of the sea. Although a long-delayed summit of the heads of state of the Caspian littoral states was held in Ashgabat in April 2002, the meeting, as expected, failed to produce a final resolution of the sea's status.

Oil Exports

Currently, Azerbaijan's only export routes are the Baku-Novorossiisk pipeline ("northern route"), which sends Azeri oil to the Russian Black Sea, and the Baku-Supsa pipeline ("western route"), which mainly carries AIOC's "early oil" from ACG to Georgia's Black Sea coast. Oil products such as lubricants also are exported by rail in tank wagons to Georgia's Black Sea ports.

In September 2000, Azerbaijan decided to attempt to boost its oil exports by switching its power-generating facilities from a fuel-oil regime to one that uses natural gas. However, problems with natural gas supplies during the winter of 2000-2001 reduced Azerbaijan's oil export potential, since fuel oil was needed domestically. As a result, the Azeri government temporarily ordered SOCAR to suspend exports. SOCAR resumed exports via Novorossiisk in December 2000, but overall, Azerbaijan had net oil exports of just 146,000 bbl/d in 2000. In 2001, preliminary data shows that Azeri net oil exports rose to 175,200 bbl/d.

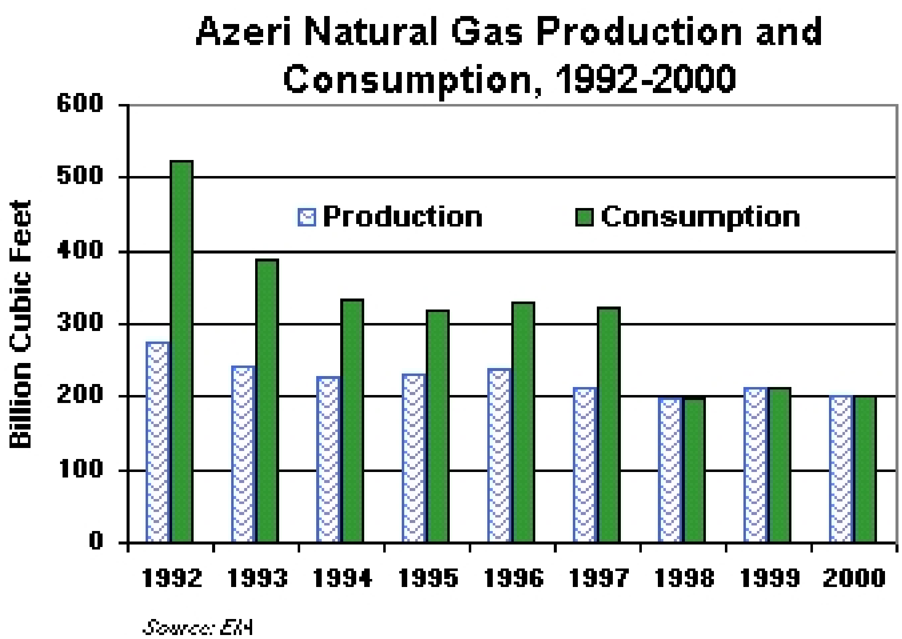
Azerbaijan's options for increasing its oil exports depend to a large extent on the construction of new pipelines. Several oil export pipelines from the Caspian Sea region have been under consideration, but Azerbaijan has not wavered in its support for the proposed Baku-Ceyhan pipeline. This so-called "Main Export Pipeline" would export Azeri (and possibly Kazakh) oil along a 1,040-mile route from Baku via Georgia to the Turkish Mediterranean port of Ceyhan, allowing oil to bypass the increasingly crowded Bosporus Straits. Construction of the 1-million-bbl/d-pipeline, which is estimated to cost $2.9 billion, is scheduled to begin in the summer of 2002. In addition, Iran, Russia, and Ukraine also have proposed alternative oil export routes for Azerbaijan.

Downstream/Refining

Azeri crude oil is refined domestically at two refineries: the Azerineftyag (Baku) refinery, with a capacity of 230,000 bbl/d, and the Azerneftyanajag (New Baku) refinery, which has a capacity of 212,000 bbl/d. With domestic production topping out at 311,200 bbl/d in 2001 (and half of that exported as crude oil), Azerbaijan's refineries have been running well below capacity, with overall refinery utilization rates as low as 40%. Heating oil accounts for approximately 50% of output at Azeri refineries, followed by diesel fuel (28%), gasoline (10%), motor oil (7%), kerosene (3%), and other products (2%).

Both of the country's refineries are in need of modernization, which the Azeri government estimates will cost between $600 million and $700 million. The U.S. Trade and Development Agency is financing a $600,000 feasibility study for upgrading the two refineries and the specialized oil port of Dubendi. In January 2002, ABB Lummus was named the winner of the tender to prepare the feasibility study. Modernization of the two refineries will enable Azerbaijan to process imported crude oil, thereby freeing up domestic oil for export via the Baku-Ceyhan pipeline.

NATURAL GAS



With so much international attention focused on Azerbaijan's oil potential, the country's natural gas sector has often been overlooked. Azerbaijan has proven natural gas reserves of roughly 4.4 trillion cubic feet (Tcf), with significant potential reserves, but because there is no developed infrastructure to deliver natural gas from offshore fields (the source of the majority of the country's production), natural gas has been flared off instead of being piped to markets.

In 1999, however, Azerbaijan enacted a law requiring that each oil and natural gas production project include a plan to develop its natural gas potential. In addition, in October 1999, the U.S. Trade and Development Agency signed a

$425 million agreement with SOCAR to help fund a comprehensive study on Azerbaijan's natural gas sector to assess its consumption needs and its production and export potential. According to EIA figures for 2000, Azerbaijan's natural gas production slipped by 5.6% to 200 Bcf.

Currently, the Bakhar natural gas field is the country's most important source of natural gas production, accounting for over 40% of total production in 2000. SOCAR produces approximately 85% of Azerbaijan's natural gas, and AIOC produces a small amount of associated gas as well. Azerbaijan's offshore natural gas production is more than 21 times that of its onshore production, but with output declining at Bakhar (due to a lack of new drilling), the country's future natural gas potential hinges on development of the Nakhchivan, Gunashli, and Shah Deniz fields.

Nakhchivan is estimated to contain 900 Bcf in reserves, while Gunashli could be brought online shortly. The Shah Deniz field, which is thought to be the world's largest natural gas discovery since 1978, is estimated to contain between 25 Tcf and 39 Tcf of natural gas. Development of the field, which will cost upwards of $4.5 billion including related infrastructure, should produce the first natural gas by 2004. Azerbaijan is planning to extract 286 Bcf of natural gas per year from Shah Deniz during the first stage of development, allowing Azerbaijan to become self-sufficient in natural gas.

In the meantime, however, Azerbaijan is forced to import natural gas to meet domestic demand. Although the country's natural gas consumption has been on the decline since 1991, Azerbaijan still must import natural gas, since it exports some of its own natural gas to Georgia and to northern Iran. In addition, in an effort to free up around 40,000 bbl/d more crude oil for export, in 2000 Azerbaijan made the decision to switch its power-generating facilities from a fuel oil regime to one that uses natural gas. In 2001, Azerbaijan imported 125 Bcf of natural gas from Russia, including 109 Bcf from Russian natural gas trader Itera, with the remainder from TransNafta.

Azerbaijan plans to increase natural gas imports from Russia by 13% in 2002, to 141 Bcf. Itera has an exclusive contract with SOCAR to supply the Azeri natural gas market in 2002, with supplies piped via the Shirvanovka-Gadzhigabul pipeline at $52 per 1,000 cubic meters (35,300 cubic feet). Through the first four months of 2002, Itera had supplied Azerbaijan with just over 58 Bcf of natural gas. Azerigaz, the state natural gas distribution company, completed maintenance on the Shirvanovka-Qazax pipeline in April 2002, allowing Azerbaijan to increase the volume of natural gas imports from Russia, via Georgia, to 177-212 Bcf if necessary.

Azerbaijan and Iran have been in discussions about exporting up to 70.5 Bcf of Iranian natural gas to Azerbaijan through Astara, as well as piping Iranian liquefied natural gas (LNG) to the Nakhchivan exclave through Culfa. However, the Gadzhigabul-Astara pipeline, which was built during the Soviet era, has a capacity of only 106 Bcf per year and has been inactive for the last 10 years. An investment of $20 million is needed to repair the line, while transportation of Iranian LNG to Nakhchivan is impossible without the construction of a new 28-mile pipeline segment from Khoi (Iran) to Culfa. LNG from Shah Deniz would be given to Iran over three years to compensate Iran's supply of LNG to Nakhchivan.

Natural Gas Exports

With the discovery of the Shah Deniz field in 1999, Azerbaijan's natural gas production potential expanded dramatically, setting the stage for the country to become a major net exporter of natural gas over the course of the next decade. International interest in Azerbaijan's natural gas sector has increased sharply due to Shah Deniz, and Azerigaz already has signed agreements with both Statoil and Royal Dutch/Shell to develop and export Azerbaijani natural gas. With the necessary infrastructure in place and the elimination of flaring, Azerbaijan's natural gas production could increase to as much as 1 Tcf by 2010.

On March 12, 2001, Azerbaijan signed its first major natural gas export deal when it concluded an agreement to supply Turkey with 89.2 Bcm (3.1 Tcf) of natural gas over a 15-year period, starting in 2004. Under terms of the deal, Azerbaijan will supply Turkey with 70.6 Bcf in 2004, 106 Bcf in 2005, 177 Bcf in 2006, and 233 Bcf per year from 2007 to 2018. Natural gas for the deal is expected to come primarily from the as-yet undeveloped Shah Deniz field, with SOCAR acting as supplier on behalf of all the participants of the international consortium developing the field. In order to deliver this natural gas, a Baku-Erzurum pipeline is in development, one of several natural gas export pipeline options from the Caspian Sea region that have been proposed.

COAL

Azerbaijan has no significant coal deposits, nor any domestic coal production. Azerbaijan consumes only a small amount of coal, and consumption has declined from over 26,400 short tons in 1992 to just 1,100 short tons in 2000.

ELECTRICITY

Azerbaijan's power sector has an installed generating capacity of approximately 4.8 gigawatts (GW), consisting of seven thermal plants (which supply over 85% of generating capacity) and six hydroelectric plants. Built during the Soviet era, Azerbaijan's power infrastructure is generally in poor condition, with minimal public investment and maintenance since independence. The country's economic contraction during the mid-1990s, along with systemic problems--such as prices capped below the market rate and frequent non-payment by customers--have left Azerbaijan's power sector without sufficient capital to upgrade aging power-generation facilities.

In 2000, Azerbaijan produced 17.6 billion kilowatt-hours (Bkwh) of electricity and consumed 16.7 Bkwh, but because of the country's inefficient distribution network, energy losses amounted to around 20% of the electricity that was generated. In order to supply electricity to all parts of the country, Azerbaijan imports power from Russia, Turkey, Iran, and Georgia, and the country participates in energy exchanges as well.

Electricity supplies to the Azerbaijani exclave of Nakhchivan have been a recurring problem. Iran, which supplies nearly 60% of the exclave's electricity needs, cut power supplies from October 2000 to February 2001 until

Azerbaijan paid the first installment on its $45 million debt for supplies already delivered. In addition, Azerbaijan has run up a multi-million dollar debt to Turkey for electricity supplied to Nakhchivan. Azerbaijan is participating in an EU program to create a unified energy system for Azerbaijan, Georgia, and Turkey, and in April 2000, an agreement was signed to restore the power grids between Azerbaijan, Georgia, Russia, and Armenia. Azerbaijan and Turkey agreed that Azerbaijan would repay its debt by transmitting Russian and Azeri electricity back to Turkey via Georgia.

President Aliyev issued a decree in 1996 to transform the state power company, Azerenergy, into a state-owned, closed, joint-stock company, and issued a five-year program for privatization after the company's outstanding debts were paid. After a failed privatization of 16 distribution networks in 2000 (bids were received for only 4 networks), Azerbaijan decided to divide the national grid into five zones (Baku, Nakhchivan, North (Sumqayit), South (Ali Bayramli) and West (Ganja)), then form joint-stock companies at these regional grids and give them to foreign investors to manage. Power stations are to remain state-owned initially. In November 2000, the Ministry of State Property opened the tender packages for the privatization of *Bakuelectricshebeke* (Baku electric network).

Several projects are underway to restore and add new capacity to Azerbaijan's power sector. In May 2000, the country's 4,000-MW Yenikand hydroelectric station was finally completed, significantly boosting capacity. Construction originally began in 1985, but was suspended two years later and only resumed in 1996 with the aid of a $53 million loan from the World Bank. Reconstruction of the $41 million, 360-MW Mingechaur hydroelectric station on the Kura River was finished in 2001.

In December 2000, construction began on the $201 million Severnaya power plant, to be built with the help of Japanese companies Mitsui and Mitsubishi. Construction of the 400-MW power unit was 70% complete in April 2002, with a planned launch date in July 2002. In addition, in October 2000 the German KFW bank allocated the second credit tranche of $15 million for the construction of substations and acquisition of technical equipment for Azerbaijan's power sector. Overall, analysts have estimated that the large-scale upgrades needed by Azerbaijan's power sector could cost $2.5 billion.

COUNTRY OVERVIEW

President: Heydar Aliyev (since June 18, 1993; re-elected to a second, five-year term on October 11, 1998)
Prime Minister: Artur Rasizade (since November 26, 1996)
Independence: August 30, 1991 (from Soviet Union); National holiday: Independence Day, May 28
Population (7/01E): 7.8 million
Location: Southwestern Asia, bordering the Caspian Sea, between Iran and Russia
Size: 33,436 square miles (slightly smaller than Maine)
Major Cities: Baku (capital), Ganja, Mingechaur, Nakhchivan, Stepanakert, Sumqayit, Yevlakh
Languages (1995E): Azerbaijani (Azeri) 89%, Russian 3%, Armenian 2%, other 6%
Ethnic Groups (1998E): Azeri 90%, Dagestani 3.2%, Russian 2.5%, Armenian 2% (almost all Armenians live in the separatist Nagorno-Karabakh region), other 2.3%
Religions (1995E): Muslim 93.4%, Russian Orthodox 2.5%, Armenian Orthodox 2.3%, other 1.8%. Note: religious affiliation is still nominal in Azerbaijan; percentages for actual practicing adherents are much lower.

ECONOMIC OVERVIEW

Minister of Economic Development: Farhad Aliyev
Minister of Finance: Avaz Alakbarov
Currency: Manat
Exchange Rate (1/02): U.S. $1 = 4,770 manats
Nominal Gross Domestic Product (GDP) (2001E): $5.2 billion; **(2002E):** $5.7 billion
Real GDP Growth Rate (2001E): 7.5%; **(2002E):** 7.0%
Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E):

2.8%; **(2002E):** 3.5%
Official Unemployment Rate (2001E): 1.3%; **(2002E):** 1.4%
Current Account Balance (2001E): $171 million; **(2002E):** $200 million
Major Trading Partners: Turkey, Russia, Georgia, Italy, Iran, Ukraine, United Arab Emirates
Merchandise Exports (2001E): $2.32 billion; **(2002E):** $2.65 billion
Merchandise Imports (2001E): $1.62 billion; **(2002E):** $1.86 billion
Merchandise Trade Balance (2001E): $707 million; **(2002):** $790 million
Major Exports: Oil and natural gas (70%), machinery, cotton, foodstuffs
Major Imports: Machinery and equipment, foodstuffs, metals, chemicals
Gold and Foreign Exchange Reserves (2000E): $681 million
External Debt (12/01E): $1.2 billion

ENERGY OVERVIEW
Minister of Fuel & Energy Development: Macid Karimov
President, State Oil Company of Azerbaijani Republic (SOCAR): Natik Aliyev
Proven Oil Reserves (1/1/02E): 1.2 billion barrels
Oil Production (2001E): 311,200 barrels per day (bbl/d); **(2002E):** 310,000 bbl/d
Oil Consumption (2001E): 136,000 bbl/d
Net Oil Exports (2001E): 175,200 bbl/d
Crude Oil Refining Capacity (1/1/01E): 442,000 bbl/d
Natural Gas Reserves (1/1/02E): 4.4 trillion cubic feet (Tcf)
Natural Gas Production (2000E): 200 billion cubic feet (Bcf)
Natural Gas Consumption (2000E): 200 Bcf
Coal Production (2000E): none
Coal Consumption (2000E): minimal
Electricity Generation Capacity (2000E): 4.8 gigawatts
Electricity Generation (2000E): 17.6 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 16.7 Bkwh

ENVIRONMENTAL OVERVIEW
Minister of Ecology & Natural Resources: Huseyngulu Bagirov

Total Energy Consumption (2000E): 0.53 quadrillion Btu* (0.1% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 12.5 million metric tons of carbon (0.2% of world carbon emissions)
Per Capita Energy Consumption (2000E): 66.0 million Btu (vs U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 1.6 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 155,556 Btu/$1990 (vs U.S. value of 10,918 Btu/$1990)**
Carbon Intensity (2000E): 3.67 metric tons of carbon/thousand $1990 (vs U.S. value of 0.17 metric tons/thousand $1990)
Sectoral Share of Energy Consumption (1998E): Industrial (38.6%), Residential (9.2%), Transportation (48.9%), Commercial (3.3%)
Sectoral Share of Carbon Emissions (1998E): Industrial (49.3%), Residential (11.2%), Transportation (35.1%), Commercial (4.4%)
Fuel Share of Energy Consumption (1999E): Oil (56.5%), Natural Gas (39.0%), Hydroelectric (4.2%)
Fuel Share of Carbon Emissions (1999E): Oil (48.9%), Natural Gas (51.1%)
Renewable Energy Consumption (1998E): 20.4 trillion Btu* (22% increase from 1997)
Number of People per Motor Vehicle (1998): 21.3 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 16th, 1995). Ratified the Kyoto Protocol on September 28, 2000.
Major Environmental Issues: local scientists consider the Abseron Yasaqligi (Absheron Peninsula) (including Baku and Sumqayit) and the Caspian Sea to be the most ecologically devastated area in the world because of severe air, water, and soil pollution; soil pollution results from the use of DDT as a pesticide and also from toxic defoliants used in the production of cotton.
Major International Environmental Agreements: A party to the

Conventions on Biodiversity, Climate Change, Climate Change-Kyoto Protocol, Desertification, Endangered Species, Marine Dumping, Ozone Layer Protection. Has signed, but not ratified: none.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY

Organization: State Oil Company of Azerbaijani Republic (SOCAR); Azerigaz (state natural gas distribution company); Azerenergo (state electric company)
Major Oil Ports: Baku
Oil Export Pipelines: Baku-Novorossiisk (via Russia; "early oil" northern route), Baku-Supsa (via Georgia; "early oil" western route)
Major Oil Refineries (Capacities 1/1/02E): Azerineftyag (Baku) (230,000 bbl/d), and Azerneftyanajag (New Baku) (212,000 bbl/d)
Major Power Plants: Yenikand (4,000 megawatts, MW) (hydro), Azerbaijan Station near Mingechaur (2,100 megawatts, MW), Ali-Bayramli (1,100 MW)

Sources for this report include: Associated Press, BBC Monitoring International Reports, Central Asia & Caucasus Business Report, Caspian News Agency, Caspian Business Report, CIA World Factbook, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, Economist Intelligence Unit ViewsWire, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, ITAR-TASS News Agency, Oil and Gas Journal, Petroleum Economist, Platt's Oilgram News, Radio Free Europe/Radio Liberty, Reuters, U.S. Department *of Commerce's Business Information Service for the Newly Independent States (BISNIS), U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, World Markets Online.*

Links

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EIA: Caspian Sea Region

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May 2002

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Iran

Iran is OPEC's second largest oil producer and holds 9% of the world's oil reserves and 15% of its natural gas reserves. Additionally, Iran is a focal point for regional security issues.

Information contained in this report is the best available as of May 2002 and is subject to change.

GENERAL BACKGROUND

Iran's economy, which relies heavily on oil export revenues (around 80% of total export earnings, 40%-50% of the government budget, and 10%-20% of GDP), was hit hard by the plunge in oil prices during 1998 and early 1999, but with the rebound in oil prices since then, has recovered somewhat. For 2001, Iran's real GDP grew by around 4.3%; for 2002 it is expected to grow at a slightly lower, 3.5% rate. Relatively high oil export revenues the past year or two have allowed Iran to set up an oil stabilization fund. In early February 2002, there were reports that Iran was considering tapping into the fund.

Despite relatively high oil export revenues, Iran continues to face budgetary pressures, a rapidly growing, young population with limited job prospects and high levels of unemployment; heavy dependence on oil revenues; significant external debt (including a high proportion of short-term debt); high levels of poverty; expensive state subsidies (billions of dollars per year) on many basic goods; a large, inefficient public sector and state monopolies (bonyads, which control at least a quarter of the economy and constitutionally are answerable only to supreme leader Ayatollah Ali Khamenei); international isolation and sanctions. These problems, and the lack of obvious progress in addressing them, have led to growing social unrest in Iran, with street riots taking place in November 2001, and large demonstrations by teachers demanding higher wages in January 2002.

To cope with its economic (and social) problems, Iran's government has proposed a variety of privatization and other restructuring and diversification measures, although these remain politically contentious. Iran also has set up a "stabilization fund" for above-budget oil revenues, which amounted to billions of dollars in 2001. Iran also is supposed to be moving ahead with a plan to unify its two major exchange rates -- official and "floating" -- this year. Finally, Iran has expressed interest in joining the World Trade Organization (WTO), although this would require that significant, and politically problematic, economic reforms be carried out by Iran (in February 2002, the United States blocked Iran's application from moving ahead).

In September 1999, President Khatami announced an ambitious program to privatize several major industries, including communications, post, rail, petrochemicals, and even upstream oil and natural gas to an extent, as part of the "total restructuring" of the Iranian economy called for in the country's latest five-year economic plan (which began in March 2000). The five-year plan also targets the creation of 750,000 new jobs per year, average annual real GDP growth of 6% over the period, reduction in subsidies for basic commodities (bread, rice, sugar, vegetable oil, wheat, fuels), plus a wide range of fiscal and structural reforms. Implementation of these plans, however, has been delayed by lack of domestic political consensus (as well as the Iranian constitution). In November 1999, the powerful (and conservative) "Council of Guardians" rejected a bill which would have exempted foreign companies in an offshore free-trade zone from threats of nationalization. More recently, the Council of Guardians vetoed planned reforms to Iran's mining sector. In August 2001, Iran's new Economy Minister, Tahmasb Mazaheri, called for the creation of a privatization organization, and said that unemployment was unacceptably high.

In February 2002, Iran's Parliament passed legislation to reform the country's tax code, substantially reducing corporate tax rates and possibly adding a value-added tax, among other things. It is feared that these tax reform measures could jeopardize Iran's projections of a 29% increase in tax revenues in its 2002 budget. However, Iran also is considering the taxation of bonyads for the first time ever. This could raise large sums of money for Iran's treasury, although the organizations likely will prove difficult to tax due to their financial opacity.

Iran is attempting to diversify by investing some of its oil revenues in other areas, including petrochemicals. Iran's non-oil exports appear to have increased significantly in recent years. Iran also is hoping to attract billions of dollars worth of foreign investment to the country by creating a more favorable investment climate (i.e., reduced restrictions and duties on imports, creation of free-trade zones). In May 2001, the Majlis approved the "Law on the Attraction and Protection of Foreign Investment," which aims at encouraging foreign investment by streamlining procedures, guaranteeing profit repatriation, and more. This Law represented the first foreign investment act passed by Iran's legislature since the 1978/79 revolution, and would supercede decades of legislation. However, this legislation has not yet come into effect due to disagreements between reformers and conservatives. In June 2001, the Council of Guardians rejected the bill as passed by the Majlis the previous month. In November 2001, the Majlis passed a second, heavily amended, version of the bill. Although this version was far weaker than the first bill, the Council of Guardians again rejected it (in December 2001). As of May 2002, efforts to encourage foreign investment in Iran remain stalled.

On February 18, 2000, Iran held its sixth parliamentary elections since the 1978/79 revolution, with an overwhelming victory for the reformist coalition. Presidential elections were held in June 2001, and President Khatami won reelection by a wide margin. In July 2001, Iran's cabinet approved formation of a "Supreme Energy Council" (SEC), which would consist of ministers from the oil, energy, economy, commerce, mines and industries ministries, among others. The SEC would play a strategic role in overseeing Iranian energy projects.

Sanctions

The U.S. Iran-Libya Sanctions Act (ILSA) of 1996 imposes mandatory and discretionary sanctions on non-U.S. companies investing more than $20 million annually in the Iranian oil and natural gas sectors. Also, in 1995, President Clinton signed executive orders prohibiting U.S. companies and their foreign subsidiaries from conducting business with Iran, while banning any "contract for the financing of the development of petroleum resources located in Iran." In response, U.S.-based Conoco was forced to abrogate a $550-million contract to develop Iran's offshore Sirri A and E oil and natural gas fields. Following this, France's Total and Malaysia's Petronas were awarded the contract. On August 19, 1997, Executive Order 13059 reaffirmed that virtually all trade and investment activities by U.S. citizens in Iran are prohibited. In March 2000, U.S. Secretary of State Albright announced that the United States would lift certain sanctions against Iranian luxury goods. Other sanctions remain in effect, however. In late July 2001, the U.S. Congress voted overwhelmingly to renew ILSA for five more years. In May 2002, the United States announced that it would review a contract by Canada's Sheer Energy (see below) to develop an Iranian oilfield to determine whether or not it violates ILSA.

OIL

Iran holds 90 billion barrels of proven oil reserves, or roughly 9% of the world's total. The vast majority of Iran's crude oil reserves are located in giant onshore fields in the southwestern Khuzestan region near the Iraqi border and the Persian Gulf. Most of Iran's current oil production is accounted for by the following fields: Ahwaz-Bangestan (250,000 bbl/d currently, with plans to increase to 600,000 bbl/d over the next 8 years at a cost of $3 billion), Marun, Gachsaran, Agha Jari, and Bibi Hakimeh. Most of Iran's crude oil is low in sulfur, with gravities in the 30°-39° API range. During 2001, Iran produced about 3.8 million bbl/d of oil. Iran's current sustainable crude oil production capacity is estimated at around 3.85 million bbl/d, which is more than 650,000 bbl/d above Iran's latest (January 1, 2002) OPEC production quota of 3.186 million bbl/d. In August 2001, Iran's oil minister denied a report (in *Middle East Economic Survey*) that Iranian production had hit 4.1 million bbl/d.

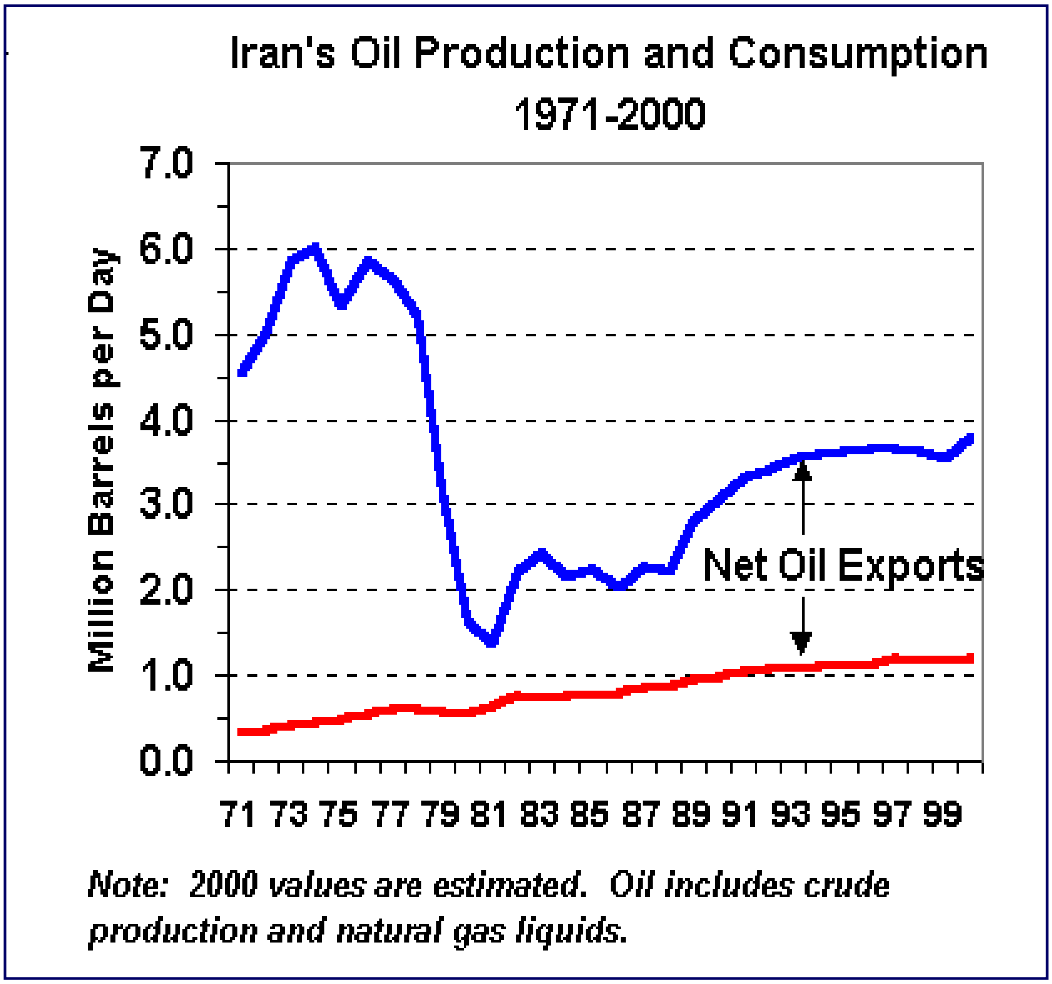
In 2001, Iran consumed an estimated 1.1 million bbl/d of oil and had net exports of around 2.7 million bbl/d Around half of Iran's oil exports go to Asian markets, with the remainder going to Europe and Africa. Iran's domestic oil consumption is increasing rapidly (about 7% per year) as the economy and population grow. In addition, Iran subsidizes the price of oil products heavily, resulting in a large amount of waste and inefficiency in oil consumption. Currently, and in spite of being a major net oil exporter, Iran is forced to spend around $1 billion per year to import oil products (mainly gasoline) which it cannot produce locally.

It is possible that with sufficient investment, Iran could increase its oil production capacity significantly. Iran produced 6 million bbl/d in 1974, but has not surpassed 3.8 million bbl/d on an annual basis since the 1978/79 Iranian revolution. During the 1980s, it is believed that Iran may have maintained production levels at some older fields only by using methods which have permanently damaged the fields. Also, Iran's oilfields are -- according to Oil Minister Zanganeh -- experiencing a depletion rate of 250,000-300,000 bbl/d per year, and are in need of upgrading and modernization. Despite these problems, Iran has ambitious plans to double national oil production -- to around 8 million bbl/d -- by 2025 or so, and is counting on foreign investment to accomplish this. Over the next four years, Iran is aiming to double foreign investment in the hydrocarbons sector to $24 billion. The country reportedly also hopes to increase its oil production capacity to 4.5 million bbl/d by 2004.

In October 1999, Iran announced that it had made its biggest oil discovery in 30 years, a giant onshore field called Azadegan located in the southwestern province of Khuzestan, a few miles east of the border with Iraq. According to Iran's Oil Minister Zanganeh, the Azadegan field could contain oil reserves of up to 24 billion barrels, with potential production of 300,000-400,000 bbl/d. On November 1, 2000, agreement was reached between Japan and Iran for Japanese firms (Japex and Indonesia Petroleum, both majority-owned by the Japan National Oil Company -- JNOC) to receive priority negotiating rights in developing Azadegan. In exchange, Japan is to loan Iran $3 billion; in April 2002, the second $1 billion installment on a $3 billion credit line was disbursed. In January 2001, the Majlis approved development of Azadegan by foreign investors using the so-called "buyback" model (see below). A contract was signed in July 2001.

Since 1995, NIOC has made several sizable oil discoveries, including the huge (3-5 billion barrels) Darkhovin onshore oilfield, located near Abadan and containing low sulfur, 39° API crude oil. In late June 2001, Italy's ENI signed a nearly $1 billion, 5 1/2-year buyback deal to develop Darkhovin, with the added incentive of a limited risk/reward element (payment is to be linked to production capacity). ENI has a 60% stake in the project, with NIOC holding the remaining 40%. Ultimately, production at Darkhovin is expected to reach 160,000 bbl/d.

In February 2001, NIOC announced the discovery of a very large offshore oil field, named Dasht-e Abadan, in shallow waters near the port city of Abadan. According to a top NIOC official, Dasht-e Abadan could contain reserves "comparable" in size to Azadegan.



Foreign Investment/Buybacks

The Iranian constitution prohibits the granting of petroleum rights on a concessionary basis or direct equity stake. However, the 1987 Petroleum Law permits the establishment of contracts between the Ministry of Petroleum, state companies and "local and foreign national persons and legal entities." "Buyback" contracts, for instance, are arrangements in which the contractor funds all investments, receives remuneration from NIOC in the form of an allocated production share, then transfers operation of the field to NIOC after the contract is completed. This system has drawbacks for both sides: by offering a fixed rate of return (usually around 15%-17%), NIOC bears all the risk of low oil prices. If prices drop, NIOC has to sell more oil or natural gas to meet the compensation figure. At the same time, companies have no guarantee that they will be permitted to develop their discoveries, let alone operate them. Finally, companies do not like the short terms of buyback contracts.

The first major project under the buyback investment scheme became operational in October 1998, when the offshore Sirri A oil field (operated by Total and Malaysia's Petronas) began production at 7,000 bbl/d (Sirri A currently is producing around 20,000 bbl/d). The neighboring Sirri E field began production in February 1999, with production at the two fields expected to reach 120,000 bbl/d.

In March 1999, France's Elf Aquitaine and Italy's Eni/Agip were awarded a $1-billion contract for a secondary recovery program at the offshore, 1.5-billion-barrel Doroud oil and natural gas field near Kharg Island. The program is intended to boost production from current levels of around 136,000 bbl/d to as high as 220,000 bbl/d within four years. TotalFinaElf is operator of the project, with a 55% share, while Eni holds the other 45%.

In April 1999, Iran awarded Canada's Bow Valley Energy, along with the former Elf Aquitaine (now TotalFinaElf), a buyback contract to develop the offshore Balal field. The field, which contains some 80 million barrels of reserves, will produce up to 40,000 bbl/d, possibly by the end of 2002. In February 2001, ENI-Agip acquired a 38.25% share in Balal from TotalFinaElf, which continues to hold a 46.75% stake in the field. Bow Valley holds a 15% share.

In November 2000, Norway's Statoil signed a series of agreements with NIOC to explore for oil in the Strait of Hormuz area. The two companies also will cooperate on developing a natural gas-to-liquids processing plant for four southern onshore fields, and possibly will develop the Salman offshore field at a cost of $850 million, with eventual production of 130,000 bbl/d. Iran appears to be accelerating its plans to boost production of natural gas liquids (NGL), as well as liquefied petroleum gas (LPG). NGL expansion plans, including a $500 million plan to build two NGL plans on the south coast of Iran, are aimed mainly at making ethane feedstock available for Iran's growing petrochemical industry.

A much-sought-after deal to develop the giant Bangestan field has been delayed several times after an expected award in 2001. Bangestan includes three oilfields (Anwaz, Mansuri, Ab-Teymour) which currently produce about 250,000 bbl/d of oil. Bidders on a project to raise this oil output to 600,000 bbl/d include TotalFinaElf, Shell, Eni, and BP.

In May 2002, Iran's Oil Ministry signed a $585 million buyback contract with local company PetroIran to develop the Foroozan and Esfandiar offshore oilfields. PetroIran is expected to increase production at the fields from around 40,000 bbl/d at present to 109,000 bbl/d within 3 years. Iran's Oil Ministry will hold a 51% stake in the project. The two oilfields straddle the border with Saudi Arabia's Lulu and Marjan fields.

In other news related to "buyback" deals, the Cheshmeh-Khosh field, which had been awarded to Spain's Cepsa for $300 million, is likely to be re-awarded to a consortium of Cepsa and OMV. The two companies are to raise crude production at the field from 30,000 bbl/d to 80,000 bbl/d within four years.

Recently, Iran appears to have had some second thoughts about buybacks (including charges of corruption, insufficient benefits to Iran, and also worries that buybacks are attracting too little investment), and reportedly is considering substantial changes in the system. As mentioned above, the July 2001 ENI deal to develop Darkhovin included a limited risk/reward element as an added incentive for foreign investment. In late May 2002, Canada's Sheer Energy became the first foreign company since then to reach a deal ($80 million to develop the Masjed-I-Suleyman, or MIS, field) under the ENI terms. The Sheer deal also was the first since the 9/11 terrorist attacks on the United States, and President Bush's January 2002 State of the Union address in which he labeled Iran as constituting part of an "Axis of Evil." The United States has announced that it will review the Sheer contract to develop MIS to determine whether or not it violates ILSA. Under this deal, Sheer Energy aims to boost MIS production from 4,500 bbl/d to 20,000 bbl/d. In general, however, the addition of a limited risk/reward element has not attracted the flood of foreign energy investment which Iran both needs and wants. As a result, Iran reportedly is considering a further modification to its "buy-back" model, possibly extending the length of such contracts from the current 5-7 years.

Besides economics, new oil and gas deals with foreign companies have been slowed in recent months by an investigation by the conservative judiciary into

Iran's oil ministry. The probe is looking into possible improprieties in $21 billion worth of oil and gas deals signed between 1997 and 2001.

Onshore Developments

NIOC's onshore field development work is concentrated mainly on sustaining output levels from large, aging fields. Consequently, enhanced oil recovery (EOR) programs, including natural gas injection, are underway at a number of fields, including Marun, Karanj, and the presently inactive Parsi fields. EOR programs will require sizeable amounts of natural gas, infrastructure development, and financing.

Although NIOC has run into difficulties in implementing EOR programs at some of its fields mentioned above (i.e., Agha Jari, Binak, Kupal, and Ramshahr) fields, it has been successful in many other cases. One example is NIOC's development work at Gachsaran, which contains in-place reserves of 53 billion barrels and a large-scale natural gas injection capacity which should help increase production.

Offshore Developments

The Doroud 1&2, Salman, Abuzar, Foroozan, and Sirri fields comprised the bulk of Iran's offshore output, all of which is exported. Iran plans extensive development of existing offshore fields and hopes to raise its offshore production capacity to 1.1 million bbl/d by 2003 (from around 600,000 bbl/d now). It is estimated that development of new offshore Persian Gulf and Caspian Sea oil fields will require investment of $8-$10 billion.

The 105-million barrel Balal field, discovered in the 1970s by an ARCO/Murphy consortium, was never developed even though an oil pipeline connecting the field to the Lavan Island export terminal was laid. As mentioned above, Canada's Bow Valley Energy Ltd. is now conducting detailed engineering work, including a 3-D seismic survey, on the Balal field. Balal likely will require extensive water injection and other secondary recovery methods, especially in later years.

On November 14, 1999, Shell announced that it had been chosen for a buyback project to develop the Soroush and Nowrooz offshore oil fields, both of which were closed during the 1980-1988 Iran-Iraq war. These fields are located offshore about 50 miles west of Kharg Island and contain estimated recoverable reserves of around 1 billion barrels of mainly heavy oil. Soroush was one of the original 11 projects put out for tender by NIOC in 1995, and the project calls for Shell to increase output at Soroush-Nowrooz to 150,000 bbl/d by 2003. In late 2001 and early 2002, Shell brought part of the $1.1 billion Soroush-Nowrooz development online, with production at Soroush expected to reach 195,000 bbl/d by 2004. Nowrooz is expected to come online by the end of 2002, with heavy crude production of 60,000 bbl/d expected.

NIOC also would like to develop five oil and natural gas fields in the Hormuz region: Henjam A (known as West Bukha by Oman; the two countries are discussing possible joint development); the A field near Lavan Island; the Esfandir field near Kharg Island; and two structures near the South Pars natural gas field. According to NIOC, the five Henjam fields hold an estimated 400 million barrels of oil and have a production potential of 80,000 bbl/d. Other Iranian oil fields slated for increases include Doroud, Nosrat, Farzam, and Salman (to 130,000 bbl/d by 2004 from 105,000 bbl/d at present).

Caspian Sea Region

Aside from acting as a transit center for other countries' oil and natural gas exports from the Caspian Sea, Iran has potentially significant Caspian reserves of its own, including up to 15 billion barrels of oil and 11 trillion cubic feet of natural gas. It is important to note, however, that almost none of this is "proven" to be recoverable (although preliminary seismic surveys conducted by Lasmo and Shell indicated 2.5 billion barrels of oil). Currently, Iran has no oil or natural gas production in the Caspian region, although in March 2001, NIOC signed a $226-million deal with Sweden's GVA Consultants and Iran's Sadra to build an oil rig in the Caspian Sea off

Mazandaran province. This marks Iran's first exploration attempt in the Caspian Sea, whose legal status among regional states remains in dispute.

At the present time, Iran maintains the most isolated position among the Caspian Sea's littoral states on the division of the Sea. Iran insists that regional treaties signed in 1921 and 1940 between Iran and the former Soviet Union, which call for joint sharing of the Caspian's resources between the two countries, remain valid. Iran has rejected as invalid all unilateral and bilateral agreements on the utilization of the Sea. While Iran agrees that a new legal convention is necessary, Iranian Foreign Minister Kamal Kharrazi told a meeting of deputy foreign ministers of the Caspian states in Tehran in February 2001 that the 1921 and 1940 treaties should be the basis for adopting a new legal regime.

As such, Iran is insisting that either the Sea should be used in common, or its floor and water basin should be divided into equal shares. Iran's preference is for the countries around the Sea to use it by consensus. Under this plan, the so-called "condominium" approach, the development of the Caspian Sea would be undertaken jointly by all of the littoral states. Iran wants all Caspian states to approve any offshore oil developments until the legal status of the Caspian Sea is agreed upon by all of the littoral countries. Another Iranian suggestion is that the littoral states should suspend all work in the Caspian Sea until the new legal status of the Caspian is determined. However, several countries are proceeding with development of subsea resources in what are generally considered to be their national waters, making the condominium approach less likely.

Iran has indicated a willingness to divide the Caspian Sea into national sectors, but only provided there is equal division of the Sea, giving each country 20% of the sea floor and surface of the Caspian. However, using the equidistant method of dividing the seabed on which Kazakhstan, Azerbaijan, and Russia have agreed, Iran would only receive about 12%-13% of the Sea. Both Kazakhstan and Azerbaijan openly have opposed Iran's proposal to divide the Caspian into five equal sectors, stating that that does not correspond to historical traditions. Nevertheless, Iran continues to insist on receiving 20% of the Sea, and diplomats involved in the working group negotiations have said that Iran has been willing to bide its time in talks in a bid to maximize its share of the Caspian Sea. In March 2002, however, Iran's Oil Minister Zangeneh asserted that Iran would begin exploiting its fifth of the Sea within a short time, and would not permit "any other party to engage in oil exploration" in this area.

As of May 2002, no agreement has been reached among Caspian Sea region states on this matter. In late April 2002, a meeting between the five Caspian littoral states ended without agreement on a new treaty. On May 20, 2002, Iran and Azerbaijan also failed to reach agreement on Caspian Sea division. On July 23, 2001, tensions flared in the Caspian Sea region when an Iranian gunboat intercepted two BP oil exploration vessels off Azerbaijan's coast. Following the incident, BP suspended exploration in the disputed block (which Iran calls Alborz).

Refining and Transportation

As of January 2001, Iran had nine operational refineries with a combined capacity of 1.48 million bbl/d. In order to meet burgeoning domestic demand for middle and light distillates, Iran has imported refined products since 1982, and is attempting to boost its refining capacity to 2 million bbl/d. Two planned grassroots refineries include a 225,000-bbl/d plant at Shah Bahar and a 120,000-bbl/d unit on Qeshm Island. The $3-billion Shah Bahar refinery project was approved by the government in late 1994 and would be built by private investors.

Iran exports crude oil via four main terminals -- Kharg Island (by far the largest), Lavan Island, Sirri Island, and Ras Bahregan. Refined products are exported via the Abadan and Bandar Mahshahr terminals. Many Iranian oil export terminals were damaged during the Iran-Iraq War, but all have been rebuilt. Iran operates the largest oil tanker fleet within OPEC, with 25 ships.

Crude Swaps

In order to get around restrictions in dealing with Iran, several firms have proposed oil "swaps" involving the delivery of Caspian (Azeri, Kazakh, Turkmen) oil to refineries in northern Iran, while the same amount of Iranian oil is exported through Persian Gulf terminals. According to Iranian Oil Minister Bijan Namdar-Zangeneh, Iran is planning to retool its oil infrastructure to accommodate such swaps, including construction of a $400-million, 240-mile pipeline from the Caspian area via Iran's Caspian port of Neka to refineries in northern Iran and to Tehran. In February 2000, the National Iranian Oil Company (NIOC) awarded a Chinese consortium (led by Sinopec and CNPC) a $100-million contract for technical aspects of the project, which is expected to transport 175,000 bbl/d of Caspian crude by the end of 2002, and possibly up to 300,000 bbl/d by late 2003. European oil trading company Vitol is involved in financing the project. Iran also plans to boost capacity at its northern refineries at Arak, Tabriz, and Tehran to about 800,000 bbl/d in order to process this oil. Currently, however, despite capacity of around 50,000 bbl/d, only 15,000-20,000 bbl/d of Turkmen oil are being shipped to Neka, and then on to Tehran by the existing Neka-Tehran pipeline. An equivalent amount of Iranian oil is then made available for export via Kharg Island terminal on the Persian Gulf.

NATURAL GAS

Iran contains an estimated 812 trillion cubic feet (Tcf) in proven natural gas reserves -- the world's second largest and surpassed only by those found in Russia. The bulk of Iranian natural gas reserves are located in non-associated fields, and have not been developed, meaning that Iran has huge potential for gas development. Besides domestic consumption, which is expected to increase more than 70% by 2005, Iran also has the potential to be a large natural gas exporter. In 2000, Iran produced about 2.1 Tcf of natural gas. Currently, natural gas accounts for around nearly half of Iran's total energy consumption, and the government plans billions of dollars worth of further investment in coming years to increase this share.

South Pars

Iran's largest non-associated natural gas field is South Pars, geologically an extension of Qatar's 380-Tcf North Field. South Pars was first identified in 1988 and originally appraised at 128 Tcf in the early 1990s. Current estimates are that South Pars contains around 280 Tcf of gas, of which a large fraction will be recoverable, and over 17 billion barrels of liquids. Development of South Pars is Iran's largest energy project, and already has attracted around $20 billion in investment. Natural gas from South Pars largely is slated to be shipped north via the planned 56-inch, $500 million, IGAT-3 pipeline (a section of which is now being built by Russian and local contractors), as well as a possible IGAT-4 line, and then reinjected to boost oil output at the mature Aghajari field (output peaked at 1 million bbl/d in 1974, but has since fallen to 200,000 bbl/d), and possibly the Ahwaz and Mansouri fields (which make up part of the huge Bangestan reservoir in the southwest Khuzestan region). South Pars natural gas also could be exported, both by pipeline and possibly by liquefied natural gas (LNG) tanker. Initial gas production from South Pars is expected this year, with sales from the field possibly earning Iran as much as $11 billion per year over 30 years, according to Iran's Oil Ministry.

On September 29, 1997, Total (now TotalFinaElf) signed a $2-billion deal (along with Russia's Gazprom and Malaysia's Petronas) to explore South Pars and to help develop the field during Phase 2 and 3 of its development. NIOC estimates that South Pars has a natural gas production potential of up to 8 billion cubic feet per day (Bcf/d) from four individual reservoirs. Phase 1, which is being handled by Petropars (owned 60% by NIOC), has been delayed several times and now is scheduled for partial completion by the end of 2002 (about 18 months behind schedule), involves production of 900 million cubic feet per day (Mmcf/d) of natural gas and 40,000 bbl/d of condensate. This first phase is being carried out by the Petroleum Development and Engineering Company (PEDEC), an affiliate of NIOC, while TotalFinaElf's consortium is responsible for Phases 2 and 3.

In August 1999, Total signed a $110-million contract with Hyundai Heavy Industries for construction of twin undersea pipelines from South Pars to onshore facilities at Asaluyeh. In March 2002, Hyundai signed another contract, this one for $1 billion, to build four natural gas processing trains. Eventually, Phases 2 and 3 are expected to produce around 2 Bcf per day of natural gas, and 80,000 bbl/d of condensates. The Asaluyeh facility comprises four natural gas processing trains, sulphur recovery units, condensate stabilization and storage units, and export compressors. In March 2002, TotalFinaElf announced that Phases 2 and 3 of South Pars had begun to come onstream.

Phases 4 and 5, estimated to cost $1.9 billion each, are being handled by ENI and Petropars, and involve construction (by Aip and Petropars) of onshore treatment facilities at the port of Bandar Asaluyeh. These two phases are expected to come online by late 2004 or early 2005. Phases 6 through 8, which are to produce a combined 3 Bcf/d of natural gas and 120,000 bbl/d of condensate, are being handled by Petropars and, in part, by the UK's Enterprise Oil (which acquired a 20% stake in late 2000, but since then expressed interest in pulling out; recently, Enterprise was acquired by Shell Oil). If Enterprise Oil does pull out of South Pars, Norway's Statoil reportedly has signed a Memorandum of Understanding to take its place on Phases 6-8.

Meanwhile, several international bidders reportedly have been short-listed for phases 9 through 12, but little progress has been made to date. Phases 9 and 10 are expected to supply the domestic market while phases 11 and 12 are slated for LNG export and condensate production. Companies reportedly interested in all or parts of phases 9-12 (expected to cost $4 billion) include BP, Eni, TotalFinaElf, and Statoil.

Other Natural Gas Development

In addition to South Pars, the 48-Tcf North Pars development may also be part of Iran's long-term natural gas utilization plans. Development plans call for 3.6 Bcf/d of natural gas production, of which 1.2 Bcf/d would be re-injected into the onshore Gachsaran, Bibi Hakimeh, and Binak oil fields. The other 2.4 Bcf/d would be sent to the more mature Agha Jari oil field. Negotiations on the field stalled in 1995, but Shell reportedly renewed its interest in 1998. A feasibility study on the field is scheduled to be completed in late 2001, and will determine whether or not North Pars natural gas is needed for injection into mature southern oil fields.

Besides North and South Pars, Iran aims to develop the 6.4-Tcf, non-associated Khuff (Dalan) reservoir of the Salman oil field. Salman straddles Iran's maritime border with Abu Dhabi, where it is known as the Abu Koosh field. NIOC is seeking to develop the Khuff reservoir, which could lead to the production of 500 Mmcf/d of non-associated natural gas, along with the 120,000 bbl/d of crude oil that is now being produced from a shallower reservoir. Salman natural gas could either be exported to Dubai's Jebel Ali or to domestic locations at Qeshm Island and Badar Mogham. The project cost is estimated at slightly under $600 million for a two-platform development.

Iran has made several significant natural gas field discoveries over the past year or so. These include: the 800-Bcf Zireh field in Bushehr province; the 4-Tcf Homa field in southern Fars province; the huge, 14-Tcf Tabnak natural gas field located in southern Iran. Iran's other sizable non-associated natural gas reserves include the offshore 47-Tcf North Pars natural gas field (a separate structure from South Pars), the onshore Nar-Kangan fields, the 13-Tcf Aghar and Dalan fields in Fars province, and the Sarkhoun and Mand fields.

The dual Aghar-Dalan field development has been one of National Iranian Gas Company's recent successful natural gas utilization projects. Since coming online in mid-1995, the Aghar and Dalan fields have produced approximately 600 Mmcf/d and 800 Mmcf/d, respectively. Natural gas from both fields is processed at a $300-million facility at the Dalan field, which is also the location of a 40-MW, natural-gas-fired power plant. Most of the treated natural gas from the Dalan processing plant is carried through a 212-mile pipeline for re-injection in the Marun field and other oil fields in Khuzestan province.

Natural Gas Trade

With almost unlimited natural gas production potential, Iran is looking to export large volumes of gas. Besides Turkey (see below), potential customers for Iranian gas exports include: Ukraine (Kiev reportedly is interested in building an Iran-Armenia-Georgia-Crimea-Ukraine line), Europe (possibly via Ukraine; this offer was reiterated by Ukraine's foreign minister in December 2001), Pakistan, Armenia, Azerbaijan, India, Taiwan, South Korea, and coastal China. Exports could be either via pipeline or by LNG tanker, with possible LNG export terminals at Asaluyeh or Kish Island. Iran reportedly is developing three LNG plants at a cost of $1.5 billion. In December 2001, Iran agreed to build a natural gas pipeline from Khoi in northwestern Iran to Azerbaijan.

In late January 2002, Iran and Turkey officially inauguarated a much-delayed natural gas pipeline link between the two countries. This follows several years of delays due to economic, political, and technical factors. In 1996, Iran and Turkey had signed a $20-billion agreement that called for Iran to supply Turkey with more than 8 Tcf of natural gas over a period of 22 years beginning in late 1999. Officials in Turkey and Iran variously blamed U.S. sanctions, financing problems on the Turkish leg of the $1.9 billion pipeline, economic recession in Turkey, and delays by the Iranians in completing an important metering station for delaying the project. Exports of Iranian natural gas to Turkey are expected at about 105 Bcf in 2002, rising to 350 Bcf per year by 2007. There are questions, however, whether Turkish demand will grow rapidly enough to absorb this volume of gas from Iran, in addition to gas slated to be supplied by Russia, Algeria, and Nigeria. If Turkish demand does not support the level of gas imports for which it has contracted (from Iran and others), Turkey could become an important transit center for natural gas exports to Greece and beyond. Along these lines, Greece and Iran signed a $300 agreement in March 2002 which calls for extending the natural gas pipeline from Iran to Turkey into Greece. Reportedly, the line would connect Ankara to Komotini in northern Greece. After that, gas could be transported to Europe via Bulgaria or via an undersea pipeline to Italy, where gas demand -- especially for electric power generation -- is expected to grow rapidly in coming years. A deep water option could be extremely expensive, however, making an overland route more likely.

Although India and Iran in 1993 signed a memorandum of understanding on an overland natural gas pipeline, regional political and security concerns to date have blocked completion of a feasibility study. In February 2002, Iran and Pakistan signed a memorandum of understanding on a pre-feasibility study for a possible 1,600-mile gas pipeline from southern Iran to southeastern Pakistan and on to India. Reportedly, Pakistan and Iran at one point had agreed to a natural gas line from South Pars to Multan, Pakistan, with a possible extension to Hazipur-Bijapur-Jagdishpur in northern India. Australia's BHP Billiton is the main foreign backer of the project, which could cost around $4 billion. An offshore route bypassing Pakistan is under study by Snamprogetti of Italy, but this could prove to be far too expensive to be feasible. Pakistan had said in early 2001 that it would allow supplies to cross its territory, and Iran would bear the contractual responsibility for assuring gas supplies to India, but the project does not appear likely to be implemented in the near future. .

Iran has been involved in a border dispute with Kuwait and Saudi Arabia over demarcation of the border through the northern Gulf continental shelf. This region contains the huge (7-13 Tcf) Dorra natural gas field, which Iran had begun drilling in early 2000 but stopped after complaints by Kuwait. Saudi Arabia and Kuwait (which do not recognize Iran's claims to Dorra) signed a bilateral agreement in July 2000 on dividing up the field equally between the two countries. In early 2002, there were reports that Saudi Arabia and Kuwait were planning to develop Dorra even without an agreement with Iran. Besides Kuwait, Iran also is reported to have discussed possible natural gas exports to the United Arab Emirates, although in April 2001, NIOC denied such a plan, as has Crescent Petroleum, the UAE company reportedly involved in the deal.

Besides natural gas exports, Iran also has discussed *importing* natural gas from Azerbaijan, and already imports some natural gas from Turkmenistan. This natural gas is for use in Iran's northern areas, far from the country's main natural gas reserves in the south. In December 1997, Turkmenistan launched the $190-million Korpezhe-Kurt Kui pipeline to Iran, the first natural gas export pipeline in Central Asia to bypass Russia. The 124-mile pipeline, which had an initial capacity of 141 Bcf, will have a peak capacity of 282 Bcf of natural gas per year. In 2000, Iran imported 106 Bcf from Turkmenistan via the pipeline, with that figure increasing to 154 Bcf in 2001.

According to terms of the 25-year contract between the two countries, Iran will take between 177 Bcf and 212 Bcf of natural gas from Turkmenistan annually, with 35% of Turkmen supplies allocated as payment for Iran's contribution to building the pipeline. In December 2001, the presidents of Turkmenistan and Armenia reached an agreement by which Turkmenistan will supply up to 70.6 Bcf per year of natural gas to Armenia via the Korpezhe-Kurt Kui pipeline and across Iran. Implementation of this deal is contingent on the construction of a long-delayed Iran-Armenia natural gas pipeline (in December 2001, Iran and Armenia signed a deal to build this line at a cost of around $120 million).

ELECTRIC POWER

Iran has installed power generation capacity of about around 31.5 gigawatts (GW), of which the vast majority (80% or so) is natural gas-fired, with the remainder either hydroelectric or oil-fired. As a result of significant state investment in this area, a number of new power plants (mainly hydroelectric and combined cycle) have come online recently in recent years in Iran, including the 2,000-MW Shahid Rai thermal power station in Qazvin; a 1,290-MW combined-cycle plant in Rasht; a doubling of the Tabriz power plant's capacity to 1,500 MW; two, 200-MW, steam-powered units at the Martyr Montazeri plant; a 215-MW steam-powered unit at the Ramin Power Plant; a 107-MW combined cycle generator at Montazer Qa'em Power Plant, three-fourths of the Shazand power plant near Arak in central Iran, and half of the Kerman combined-cycle plant in southeastern Iran.

With power demand growing rapidly (7%-8% annually), Iran is adding significant generation capacity -- both thermal and hydroelectric, with the goal of reaching a total generating capacity of 40 GW by 2005. The largest hydropower projects are the 3,000-megawatt (MW) Karun 3 plant, the 2,000-MW Godar-e Landar facility, a 1,000-MW station in Upper Gorvand, and the 400-MW Karkheh dam. New thermal projects include two 1,040-MW combined cycle plants in the South, an 1,100-MW combined cycle plant at Arak, and a 1,000-MW facility in Bandar Abbas. In early April 2002, the 1,000-MW, natural-gas-fired, combined-cycle Shahid Raja'i power plant came online in the northern Iranian province of Qazvin.

Iran has received offers for investment in the form of loans and build-operate-transfer (BOT) contracts. BOT contracts allow the investing company to build and operate the generating facility for a period of 15-20 years, after which time the plant is turned over to the Energy Ministry. Negotiations have taken place with international energy firms on expansion plans for power plants at Bandar Abbas, Shaid Rajai, Alborz, Ramin, and Kerman.

Although the government has considered privatization, at present Iran's power sector is run by the state-controlled Tavanir organization. Eventually, Tavanir may be broken up into smaller companies as part of a privatization package. In addition to power generation, Tavanir also is responsible for transmission. Iran has main power distribution networks: 1) The Interconnected Network, which serves all of Iran except for remote eastern and southern areas, using 440-kV and 230-kV transmission lines; 2) the Khorassan Network, which serves the eastern Khorossan province; and 3) the Sistan and Baluchistan Network, which serves the remote southeastern provinces of Sistan and Baluchistan. The government goal is to join these three networks into one national grid. Currently, around 94% of Iranians are connected to one of Iran's power grids. Iran also has power links to neighboring countries, including a recent line connecting Parsabad-e Moghan, Iran, and Imishli, Azerbaijan, and exports small amounts of power. On March 31, 2002, Iran halted power exports to Turkey, reportedly for "commercial reasons." Iran exported approximately 280 million kilowatthours of electricity to Turkey in 2001.

NUCLEAR

Currently, Iran has five small nuclear reactors, one in Tehran and four in Isfahan. Iran claims that its nuclear power is for peaceful purposes and that it will help free up oil and natural gas resources for export, thus generating additional hard-currency revenues. The U.S. State Department frequently has stated U.S. opposition to Iran's nuclear program. The United States has argued that Iran has sufficient oil and natural gas reserves for power generation, and that nuclear reactors are expensive, unnecessary, and could be used for military purposes. Iran is a signatory to the Nuclear Non-Proliferation Treaty.

In March 2001, President Khatami met with Russian President Putin and agreed to expand bilateral cooperation on nuclear power. Russia's atomic ministry has been assisting Iran on the Bushehr nuclear power facility. Work on this plant began in 1974 by West Germany, but was halted (80% complete) following the 1978/1979 revolution. Progress on Bushehr resumed when Russia signed a $780-million contract in 1995, as well as an agreement in September 1998 to complete the facility within 52 months. The 1995 contract with Russia calls for completion of the two, 1,300-MW, pressurized-light water units as well as the supply of two modern VVER-440 units. Since then, work has proceeded slowly. The United States strongly opposes the project and has in the past provided Russia with information pointing to the existence of an Iranian nuclear weapons program. In May 2002, U.S. Energy Secretary Spencer Abraham met with Alexander Rumyantsev, head of Russia's nuclear agency, and discussed this issue, with Rumyantsev stating the Russian position that Bushehr "is not a source of proliferation of nuclear material." Under the latest contract details with Russia, construction on Bushehr must be completed by March 19, 2004. Iran reportedly is to decide during 2002 whether or not to purchase a second Russian-built reactor for Bushehr once the first reactor is finished.

ENVIRONMENT

In the context of its oil-based economy, environmental issues in Iran only recently have become important. Ongoing air pollution in urban areas, which reached a crisis level in Tehran in December 1999, have highlighted the need to improve Iran's environmental record. The rush to develop oil and natural gas resources in the Caspian Sea makes oil pollution in the Caspian a real environmental threat.

Huge increases in energy consumption over the past 20 years have contributed greatly to pollution levels as Iran's carbon emissions have nearly tripled over the same time span. Large numbers of old, inefficient cars on the road lacking catalytic converters account for much of the country's air pollution. Energy prices are kept artificially low in Iran through heavy state subsidies, resulting in wasteful consumption patterns.

In addition, Iran's abundance of fossil fuel resources has tended to discourage the country's incentive to shift to cleaner alternative energy sources for its energy needs. As Iran continues to struggle with air pollution in the 21st century, however, the country likely will need to take a variety of tough measures in order to avert an environmental crisis.

Sources for this report include: Agence France Presse; AP Worldstream; BBC Summary of World Broadcasts; Calgary Herald; CIA World Factbook 2000; Deutsche Presse-Agentur; Dow Jones; DRI/WEFA; Economist Intelligence Unit Viewswire; Financial Times; Foreign Broadcast Information Service; Gulf News; Hart's Africa Oil and Gas; Hart's Asian Petroleum News; Hart's Middle East Oil and Gas; Interfax; International Herald Tribune; Iran Brief; Middle East Business Intelligence; Middle East Economic Digest; National Post; Nefte Compass, New York Times; Oil and Gas Journal; Oil and Gas Investor; Petroleum Economist; Petroleum Intelligence Weekly; Pipeline and Gas Journal; Reuters; Turkish Daily News; U.S. Energy Information Administration, World Gas Intelligence, World Markets Online.

COUNTRY OVERVIEW
President: Mohammed Khatami (since August 1997; reelected June 2001)
Supreme/Spiritual Leader: Ayatollah Ali Khamenei

Islamic Republic Proclaimed: April 1, 1979
Population (7/01E): 66.1 million
Location/Size: Middle East - between the Persian Gulf and the Caspian Sea/636,296 square miles
Major Cities: Tehran (capital), Meshed, Isfahan, Tabriz, Shiraz, Ahwaz, Kermanshah, Qom, Ardebil, Qazvin
Languages: Persian and Persian dialects (58%), Turkic and Turkic dialects (26%), Kurdish (9%), Luri (2%), Baluch (1%), Arabic (1%), Turkish (1%)
Ethnic Groups: Persian (51%), Azerbaijani (24%), Gilaki and Mazandarani (8%), Kurd (7%), Arab (3%), Lur (2%), Baluch (2%), Turkmen (2%), other (1%)
Religion: Shi'a Muslim (89%), Sunni Muslim (10%), Zoroastrian, Jewish, Christian, and Baha'i (1%)
Defense (8/98): Army (350,000), Revolutionary Guard (120,000), Navy (20,600), Air Force (40,000-45,000), army reserves (350,000)

ECONOMIC OVERVIEW
Minister of Economic Affairs and Finance: Dr. Tahmasb Mazaheri
Currency: Rial (R)
Exchange Rates (5/17/02): R 1,741 per $U.S. for official budget transactions and essential goods imports and exports, as well as external debt service; "floating" Tehran Stock Exchange (TSE) rate of around 8,000 per $U.S.
Gross Domestic Product (GDP, at market exchange rates) (2001E): $82.3 billion
Real GDP Growth Rate (2000E): 5% **(2001E):** 4.3% **(2002F):** 3.5%
Inflation Rate (2000E): 19.2%% **(2001E):** 11.7% **(2002F):** 11.5%
Unemployment Rate (2000E): 12.7% (unofficially, 16%-25%)
Current Account Balance (2000E): $12.6 billion **(2001E):** $7.3 billion **(2002F):** $5.2 billion
Major Trading Partners (2000): Japan, Italy, Germany, China, France, United Arab Emirates
Merchandise Exports (2001E): $24.1 billion
Merchandise Imports (2001E): $16.3 billion
Merchandise Trade Surplus (2001E): $7.8 billion

Major Export Products: Oil and oil products (90%), carpets, pistachios
Major Import Products: Industrial supplies (37%), machinery (30%), consumer goods (18%)
Oil Export Revenues (2001E): $20.5 billion **(2002F):** $16.4 billion
Oil Export Revenues/Total Export Revenues (2001E): around 90%
Total External Debt (3/01E): $21.2 billion

ENERGY OVERVIEW
Minister of Energy: Habibollah Bitaraf
Minister of Petroleum: Bijan Namdar-Zanganeh
Atomic Energy Organization of Iran: Gholamreza Aqazadeh
Proven Oil Reserves (1/1/02E): 89.7 billion barrels
OPEC Crude Oil Production Quota (as of 1/1/02): 3.186 MMBD
Crude Oil Production Capacity (2002E): 3.85 MMBD
Oil Production (2001E): 3.8 MMBD (of which, 3.7 MMBD was crude oil)
Oil Consumption (2001E): 1.1 MMBD
Net Oil Exports (2001E): 2.7 MMBD
Crude Oil Refining Capacity (1/1/02E): 1.48 MMBD
Major Crude Oil Customers: OECD Europe, Japan, China, South Korea
Natural Gas Reserves (1/1/02E): 812 trillion cubic feet (Tcf)
Dry Natural Gas Production (2000E): 2.13 Tcf
Natural Gas Consumption (2000E): 2.22 Tcf
Recoverable Coal Reserves (2000E): 1,885 million short tons (Mmst)
Coal Production (2000E): 1.39 Mmst
Coal Consumption (2000E): 2.15 Mmst
Net Coal Imports (2000E): 0.76 Mmst
Electric Generation Capacity (2001E): 27 gigawatts (around 90% thermal)
Electricity Consumption (2000E): 111.9 billion kilowatthours

ENVIRONMENTAL OVERVIEW
Vice President for Environmental Protection: Dr. Mrs. Masumeh Ebtekar
Total Energy Consumption (2000E): 4.72 quadrillion Btu* (1.2% of world total energy consumption)

Energy-Related Carbon Emissions (2000E): 80.8 million metric tons of carbon (1.3% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 73.8 million Btu (vs U.S. value of 351.1 million Btu)
Per Capita Carbon Emissions (2000E): 1.3 metric tons of carbon (vs U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 39,265 Btu/ $1995 (vs U.S. value of 10,919 Btu/ $1995)**
Carbon Intensity (2000E): 0.68 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**
Sectoral Share of Energy Consumption (2001E): Residential (31.0%), Industrial (27.0%), Transportation (23.6%), Commercial (8.6%)
Sectoral Share of Carbon Emissions (1998E): Industrial (39.7%), Residential (24.4%), Transportation (27.3%), Commercial (8.6%)
Fuel Share of Energy Consumption (2000E): Natural Gas (49.8%), Oil (47.7%), Coal (1.0%)
Fuel Share of Carbon Emissions (1999E): Oil (57.5%), Natural Gas (41.2%), Coal (1.3%)
Renewable Energy Consumption (1998E): 391 trillion Btu* (300.6% increase from 1997)
Number of People per Motor Vehicle (1998): 27.7 (vs U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified July 18th, 1996). Not a signatory to the Kyoto Protocol.
Major Environmental Issues: Air pollution, especially in urban areas, from vehicle emissions, refinery operations, and industrial effluents; deforestation; overgrazing; desertification; oil pollution in the Persian Gulf; inadequate supplies of potable water.
Major International Environmental Agreements: A party to Conventions on Biodiversity, Climate Change, Desertification, Endangered Species, Hazardous Wastes, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection and Wetlands. Has signed, but not ratified, Environmental Modification, Law of the Sea and Marine Life Conservation.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar, wind, wood and waste electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.
**GDP based on EIA International Energy Annual 2000

OIL AND GAS INDUSTRIES
Organizations: The Ministry of Petroleum (MoP) has overall responsibility for the country's energy sector. The MoP has four subsidiaries which function autonomously for the most part, but ultimately report to the Ministry: 1) National Iranian Oil Company (NIOC) - oil and gas exploration and production, refining and oil transportation; 2) National Iranian Gas Company (NIGC) - manages gathering, treatment, processing, transmission, distribution, and exports of gas and gas liquids; 3) National Iranian Petrochemical Company (NPC) - handles petrochemical production, distribution, and exports; and 4) National Iranian Oil Refining and Distribution Company (NIORDC) handles oil refining and transportation, with some overlap to NIOC. Also, the National Iranian Tanker Company (NITC) controls the second largest fleet of tankers in OPEC.
Foreign Oil Company Involvement: BG, Bow Valley, BP, ENI, Gazprom, Petronas, Royal Dutch/Shell, Sheer Energy, Statoil, TotalFinaElf
Major Oil Fields: Agha Jari, Ahwaz (Bangestan), Azadegan, Bibi Hakimeh, Darkhovin, Doroud, Gachsaran, Mansouri (Bangestan), Marun, Masjid-e Soleiman, Parsi, Rag-e-Safid, Soroush/Nowruz
Major Refineries (capacity, bbl/d) (1/1/02E): Abadan (400,000), Isfahan (265,000), Bandar Abbas (232,000); Tehran (225,000), Arak (150,000), Tabriz (112,000), Shiraz (40,000), Kermanshah (30,000), Lavan Island (30,000)
Major Oil Terminals: Ganaveh, Kharg Island, Lavan Island, Sirri Island, Cyrus, Ras Bahregan, Larak Island

Gas Pipeline System: IGAT-1 transports associated gas from Khuzestan area oilfields to consumption centers in the north; IGAT-2 transports non-associated gas from the Kangan and Nar fields on the Persian Gulf coast near Bandar Taheri; IGAT-3, which would run from South Pars to Tehran, is planned. Evaluation also has begun on a possible IGAT-4 line from South Pars to industrial northern Iran.

LINKS

For more information on Iran, please see these other sources on the EIA web site:
EIA - Historical Energy Data on Iran
OPEC Fact Sheet

Links to other U.S. government web sites:
2001 CIA World Factbook - Iran
U.S. Treasury Department's Office of Foreign Assets Control
U.S. State Department's Consular Information Sheet - Iran
Library of Congress Country Study on Iran

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The Center for Middle Eastern Studies (University of Texas at Austin) - Iran
Iran Online
Interests Section of the Islamic Republic of Iran in Washington, DC (in the Pakistani Embassy)

Permanent Mission of the Islamic Republic of Iran to the United Nations
Iran: Ministry of Energy
Gulf Wire
Iranian Trade
National Petrochemical Company of Iran
MENA Petroleum Bulletin
Salam Iran Home Page

Iran Weekly Press Digest
Iran Press Service
Pars Times: Iran Oil and Gas Resources
Pars Times: Persian Gulf Region
Pars Times: Caspian Sea Region

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Energy Information Administration

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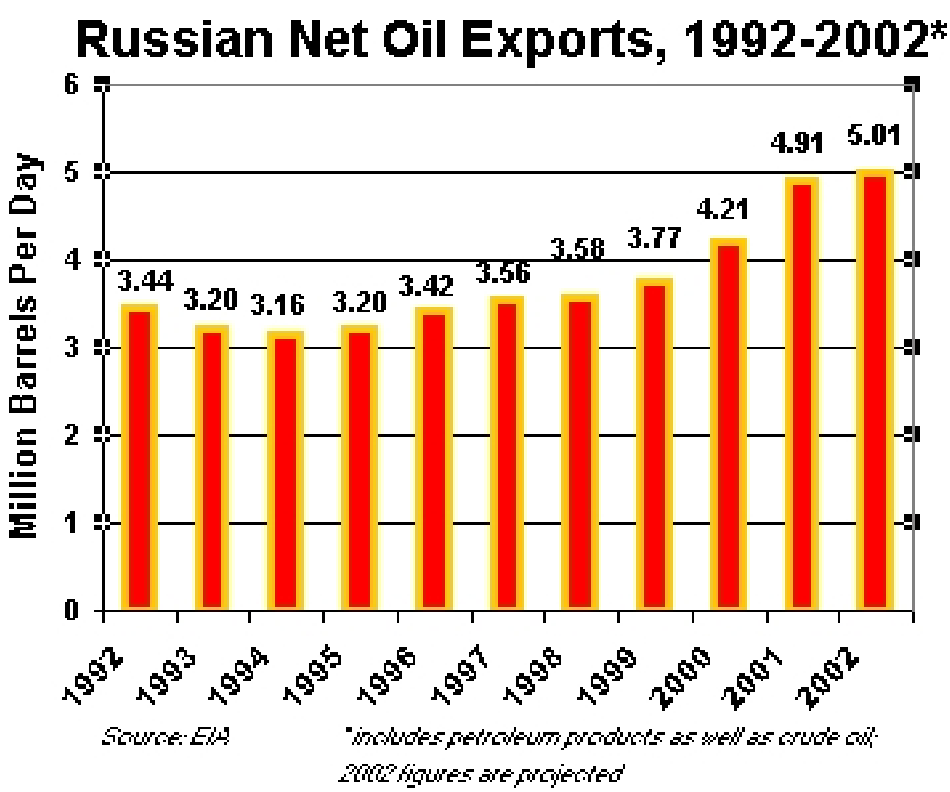
Russia: Oil and Natural Gas Exports

OIL EXPORTS
Prior to 1991, the Soviet Union was the world's largest oil exporter, with exports in excess of 12 million bbl/d at its peak. Russia, the largest republic in the U.S.S.R., also provided the bulk of its oil exports, accounting for nearly 90% of overall oil exports. Soviet oil production and exports declined throughout the 1980's, and in the aftermath of the breakup of the Soviet Union in 1991, Russia's net oil exports plummeted to just 3.16 million barrels per day (bbl/d) in 1994.

After Russia restructured its oil industry into a number of vertically-integrated, private oil companies, the country's oil production and exports began to increase again. In 2001, Russia's net oil exports rose for the seventh consecutive year, reaching 4.91 million bbl/d in net crude oil and oil product exports. Russia is now the world's second largest oil exporter, behind only Saudi Arabia. Russia's net oil exports are projected to increase again in 2002, to 5.01 million bbl/d.

Crude oil exports are a key source of income for Russia, as revenues from exports provide approximately 25% of the Russian government's income. Just a $1-per-barrel price decrease for Russia's Urals Blend benchmark brings in almost $1 billion in extra earnings. Likewise, however, a $1-per barrel decrease in the oil price is a significant blow to the Russia's budget. While Russia basked in a windfall of oil revenues during 1999-2000 when world oil prices were relatively high, the drop in world oil in 2001 cut into Russia's revenue intake.



Export Cuts
Thus, although Russia is not a

member of the Organization of Petroleum Exporting Countries (OPEC), in early 2001 the country agreed to cut crude oil exports (albeit by albeit by an unspecified amount) in an effort to shore up sagging world oil prices. Following the steep decline in world oil prices after September 11, 2001, Russia came under significant pressure from OPEC to make significant, specific reductions in its oil exports in the fourth quarter of 2001. After weeks of negotiations with OPEC members and Russian oil companies, the Russian government finally agreed to a paltry export reduction of 50,000 bbl/d in the fourth quarter. However, with the threat of a price war with OPEC looming, Russia reversed course in December, agreeing to a 150,000 bbl/d oil export cut in the first quarter of 2002.

Nevertheless, despite being restricted to exporting 30% of their production by a long-standing quota arrangement, Russia's oil producers have sought to maximize their exports by whatever means possible, constraints on export capacity notwithstanding. The discrepancy between export and domestic prices (Russian prices are typically just over half of the world market price), plus the guarantee of hard currency payment for oil exports, combine to make a compelling argument for increased sales abroad. In addition, with the opening of the Baltic Pipeline System (BPS) in December 2001, Russia increased its export capacity by 240,000 bbl/d, just when the country was expected to reduce its exports by nearly 5%.

Not surprisingly, Russia has not been 100% compliant with its pledged production cuts, and preliminary data shows that Russian oil exports actually increased in the first quarter of 2002. Government-imposed export tariffs caused a glut of crude on the Russian market, causing a price collapse and leading to calls from Russian oil companies to lift the export ceiling. Russian oil companies then sent their crude to Russian refineries, which led to an increase in oil product exports and a surplus of refined products on the market. In order to reduce the amount of crude on the market, some Russian officials have called for the creation of a strategic Russian oil reserve.

In the meantime, in March 2002, over the opposition of domestic oil companies, the Russian government announced that Russia would continue to reduce its oil exports by 150,000 bbl/d. Regardless, Russian oil companies have begun to increase their crude oil exports as world oil prices have climbed, and Transneft, Russia's state pipeline monopoly, has increased exports through its pipeline system. In addition, at the six main Baltic and Black Sea terminals for which monthly loading program are set, total exports are scheduled for around 1.767 million bbl/d in April 2002, a 60,000 bbl/d average increase over the 1.707 million bbl/d exported in March 2002. (See Figure 1).

Figure 1. Russian Crude Oil Export Loadings at Main Export Terminals (volumes in bbl/d)

Terminal	January	February	March	April
Novorossiisk	895,000	835,000	830,000	935,000
Odessa	225,000	250,000	245,000	210,000
Primorsk	190,000	210,000	235,000	245,000

Ventspils	305,000	230,000	300,000	210,000
Tuapse	105,000	90,000	97,000	102,000
Butinge	terminal closed	terminal closed	20,000	65,000
Total	**1,720,000**	**1,615,000**	**1,707,000**	**1,767,000**

Source: Reuters

Note: These volumes do not include the crude exported from Russia to central Europe via the Druzhba pipeline, which accounts for over one-third of Russia's crude exports at about 1.2 million bbl/d, nor does it include petroleum product exports. In addition, the totals do not include: Russian crude exported from Tallinn, Estonia, where it is transported by rail and marketed by a single party; Gdansk, which re-exports Druzhba pipeline volumes bound for Polish refineries; irregular exports from Feodosia, Ukraine, primarily by Yukos; or Siberian Light exports from Novorossiisk, brought in by rail. These four outlets combined supply as much as 250,000 bbl/d or as little as 60,000 bbl/d in any given month.

Export Routes
The majority of Russian oil is exported via terminals in the Baltic Sea (several ports) and Black Sea (mainly Novorossiisk). Russian crude oil also is exported to Europe via the 1.2-million bbl/d capacity Druzhba pipeline. Black Sea exports, however, must pass through the increasingly crowded Bosporus Straits. As traditional export routes through Black Sea ports have been running at full capacity and environmental concerns about the possibility of an oil spill in the Bosporus increase, Russian oil companies are turning toward ports in the Baltic countries and the Druzhba pipeline as alternatives. In addition, the integration of the Druzhba and Adria pipelines in Croatia in the fall of 2002 will give Russian oil exporters direct access to the Adriatic Sea, where where tankers can be loaded at the deep water port of Omisalj.

In addition, the Baltic Pipeline System, which began operations in December 2001, allows Russia to export oil directly from its Baltic Sea port of Primorsk rather than shipping it through Estonia, Latvia, or Lithuania. Russian oil companies also are attempting to challenge Transneft's monopoly position on export pipelines by developing pipeline projects of their own. Yukos, one of the country's largest oil companies, is negotiating with the Chinese government to build an oil pipeline to China, and several international consortiums developing oil projects on Sakhalin island are considering building pipelines to China and Japan to supply oil to customers there. Huge investments in infrastructure will be needed to bring these pipelines online.

Export Destinations
Since 1991, Russian oil exporters increasingly have shifted their focus from the countries of the

Commonwealth of Independent States (CIS) and central Europe to Western Europe. As countries in the former Soviet Union have racked up oil debts, Russian oil exporters have targeted customers in Western Europe, where demand for oil is strong, supply is limited, and payment is in cash.

The majority of Russian oil exports are going to countries such as the United Kingdom, France, Italy, Germany, and Spain. The share of net exports to countries outside the former Soviet Union rose from 53% in 1992 to 87% in 2000 as the share of net exports to former Eastern Bloc and Soviet Union countries decreased. Russia's net exports outside the CIS totaled 3.8 million bbl/d in 2000, while only 570,000 bbl/d was exported to CIS countries.

An October 2000 energy summit between the European Union (EU) and Russia, whereby the EU agreed to help Russia develop its oil and natural gas reserves in return for a long-term energy supply commitment, promises to boost Russia's oil exports. With pipeline projects such as the Baltic Pipeline System, Russia hopes to increase oil exports to Europe to over 5 million bbl/d in the future.

In addition, Russian oil exports to Asia are set to increase in the next decade with the development of oilfields in Eastern Siberia and on Sakhalin Island, and the integration of the Druzhba and Adria pipelines may even give Russia the ability to export its oil economically to the United States.

OIL TRANSIT

Russia is maneuvering to become a major player in the exploration, development, and export of oil from the Caspian Sea region. Typically, about 300,000 bbl/d of oil--mainly from Kazakhstan and Azerbaijan--from the Caspian region is exported outside the CIS through Russian oil pipelines controlled by Transneft. With Caspian Sea oil exports set to rise in coming years, Transneft is keen to attract that additional transit oil through its pipeline system in order to reap extra tariff revenues. Caspian regional oil exporters have a number of export options, but Russia is hoping to become the main transit route.

Kazakh Oil Exports via Russia

Kazakhstan exported about 270,000 bbl/d through Russia in 2001, the majority of which was sent through the Atyrau-Samara pipeline, and then via the Transneft system and exported via the Druzhba pipeline or through Baltic Sea terminals. Russia recently completed an expansion of the Atyrau-Samara pipeline that increased its capacity to 300,000 bbl/d, and Russia already has allocated a 100,000 bbl/d quota of Kazakh oil for the Baltic Pipeline System.

Kazakhstan also sent oil in 2001 via Russia's Caspian Sea port of Makhachkala, which connects to the 100,000-bbl/d-capacity Baku-Novorossiisk pipeline. However, the Caspian Pipeline Consortium (CPC) pipeline, which loaded its first tanker in October 2001, has become Kazakhstan's main export route transiting Russia. With an initial capacity of 564,000 bbl/d, the CPC pipeline exported an average of over 200,000 bbl/d of Kazakh oil via Russia in the final 2 months of 2001, and the CPC is expected to pipe around 400,000 bbl/d in 2002.

In December 2001, Kazakhstan and Russian signed an inter-governmental agreement that makes Kazakhstan eligible to transport up to 350,000 bbl/d through the Russian pipeline system in 2002. The agreement covers the Transneft system, which includes the BPS, the Atyrau-Samara pipeline, the Baku-Novorossiisk pipeline, and the Makhachkala port, but it does not include the CPC pipeline. Under the agreement, Kazakhstan can transit up to 300,000 bbl/d through the Atyrau-Samara pipeline and 50,000 bbl/d via Makhachakala and the Baku-Novorossiisk pipeline. Overall, Kazakh oil exports transiting Russia could reach 750,000 bbl/d in 2002.

Azeri Oil Exports via Russia
Azerbaijan exports a small amount of oil through Russia via the Baku-Novorossiisk pipeline. In 1996, Russia and Azerbaijan signed an intergovernmental agreement on the transit of Azeri oil through Russia, with Azerbaijan committing itself to exporting a portion of its "early oil" from the Caspian Sea via Russia. However, the pipeline has been plagued with problems, from the war in Chechnya to Azerbaijan's inability to fill it. Azerbaijan committed itself to throughput in 2000 of 46,000 bbl/d, but in the end only transported around 10,000 bbl/d via Russia.

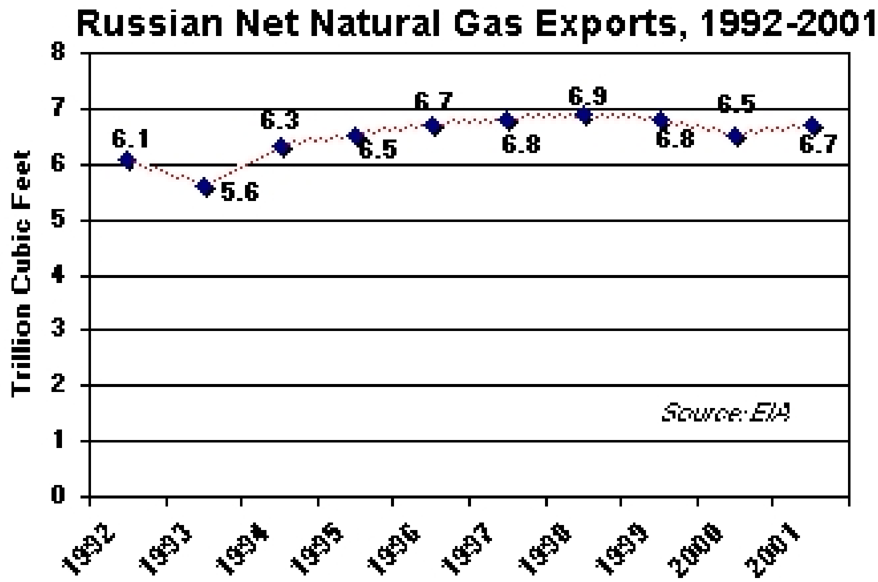
In addition, the Azerbaijan International Operating Company (AIOC), which is developing Azerbaijan's most promising fields in the Caspian Sea, has preferred to bypass Russia, piping its early oil via the Baku-Supsa western route through Georgia instead. AIOC has has been reluctant to send its oil along this route because it is longer and more expensive than the Baku-Supsa route, and also because the Baku-Novorossiisk route mixes AIOC crude with other crude oils while in transit to the oil terminal, reducing its value. Also, the tariff for Azeri oil transportation through the Baku-Novorossiisk pipeline is over seven times higher than the tariff of the Baku-Supsa route.

Nevertheless, SOCAR increased its exports via the Baku-Novorossiisk pipeline to 46,000 bbl/d, and the company plans to maintain that rate in 2002. Russia says the the capacity on the Baku-Novorossiisk pipeline can be increased to 300,000 bbl/d, but SOCAR will not have sufficient volumes to fill the pipeline, even at its present capacity, in the next few years.

Turkmen Oil Exports via Russia
Turkmenistan is looking to increase its oil exports via the Makhachkala port and then through the port's link to the Baku-Novorossiisk pipeline. Turkmenistan arranged with Transneft to export up to 50,000 bbl/d via the Baku-Novorossiisk pipeline in 2000, but Transneft determined that the Turkmen oil was not fit for the pipeline and refused to load it in the pipeline, leaving tankers loaded with Turkmen oil standing in port. Turkmenistan eventually accepted rail transportation of its oil.

According to information from the Russian Ministry of Energy, Turkmenistan transited only 90 bbl/d through Russia in 2001, against planned volumes of 9,000 bbl/d. Turkmenistan is planning to export about 20,000 bbl/d via Makhachkala and the Baku-Novorossiisk pipeline in 2002.

NATURAL GAS EXPORTS



Russia is the world's largest natural gas exporter, with 6.7 trillion cubic feet (Tcf) in net natural gas exports in 2001. Gazprom, Russia's state-run gas monopoly and the country's largest natural gas exporter, has forecast that Russia's natural gas exports will climb to 7.1 Tcf by 2002 and to 7.5 Tcf in 2005.

In addition, many Russian oil companies sit on huge natural gas reserves, which they have not developed commercially because they do not have access to lucrative export markets. Gazprom keeps firm control of Russia's pipeline network, but with restructuring in the country's natural gas sector in the works, all natural gas producers finally may receive equal pipeline access. When third-party access to Russia's natural gas transportation infrastructure becomes a reality, Russia's natural gas exports could increase dramatically: Russian oil companies currently produce approximately 2.2 Tcf of associated natural gas that could be treated and exported rather than flared off.

Already, Russian independent Arktikgaz has been given access to Gazprom's pipeline network to supply 4.2 billion cubic feet (Bcf) of natural gas to northern Ukraine from October 2001-2010. Arktikgaz also has signed contracts to supply 5.3 Bcf to Belarus and 2.1 Bcf to Georgia over the next 10 years and hopes to become the first Russian independent producer to export natural gas outside the former Soviet Union.

While these figures are minuscule compared to the amount of natural gas that Gazprom exports, it represents the first challenge to Gazprom's monopoly position on Russian natural gas exports. In March 2002, Yukos, Russia's second-largest oil company, acquired a controlling stake in Arktikgaz and announced its plans to become a major player in Russia's natural gas industry. Further restructuring of the natural gas sector and the potential break-up of Gazprom could open the export market to additional producers.

Export Markets
Historically, the majority of Russia's natural gas exports were sent to customers in Eastern Europe, but since the collapse of the Soviet Union, Russia increasingly is looking to diversify its export options. Russia continues to export significant amounts of natural gas to customers in the Commonwealth of Independent States (CIS) because of the existing natural gas distribution network linking the former Soviet republics, but Gazprom is shifting its export strategy to send more natural gas to the EU and Turkey. In addition, Russian is looking at markets in China, Japan, and possibly South Korea for its natural gas.

To the Commonwealth of Independent States

Since the breakup of the Soviet Union, Russian natural gas exports to the former Soviet republics have decreased dramatically. In the past decade, Russia has reduced its natural gas supplies to CIS customers by over 1 Tcf. Gazprom has complained that it does not receive a reasonable price for natural gas sales to CIS countries, it often receives payment at least partly in-kind, and that many CIS countries owe substantial payment arrears to the company for supplies already received. In particular, Ukraine, through which Russia sends over 90% of its natural gas exports to Europe, owes Gazprom nearly $2 billion for natural gas supplies.

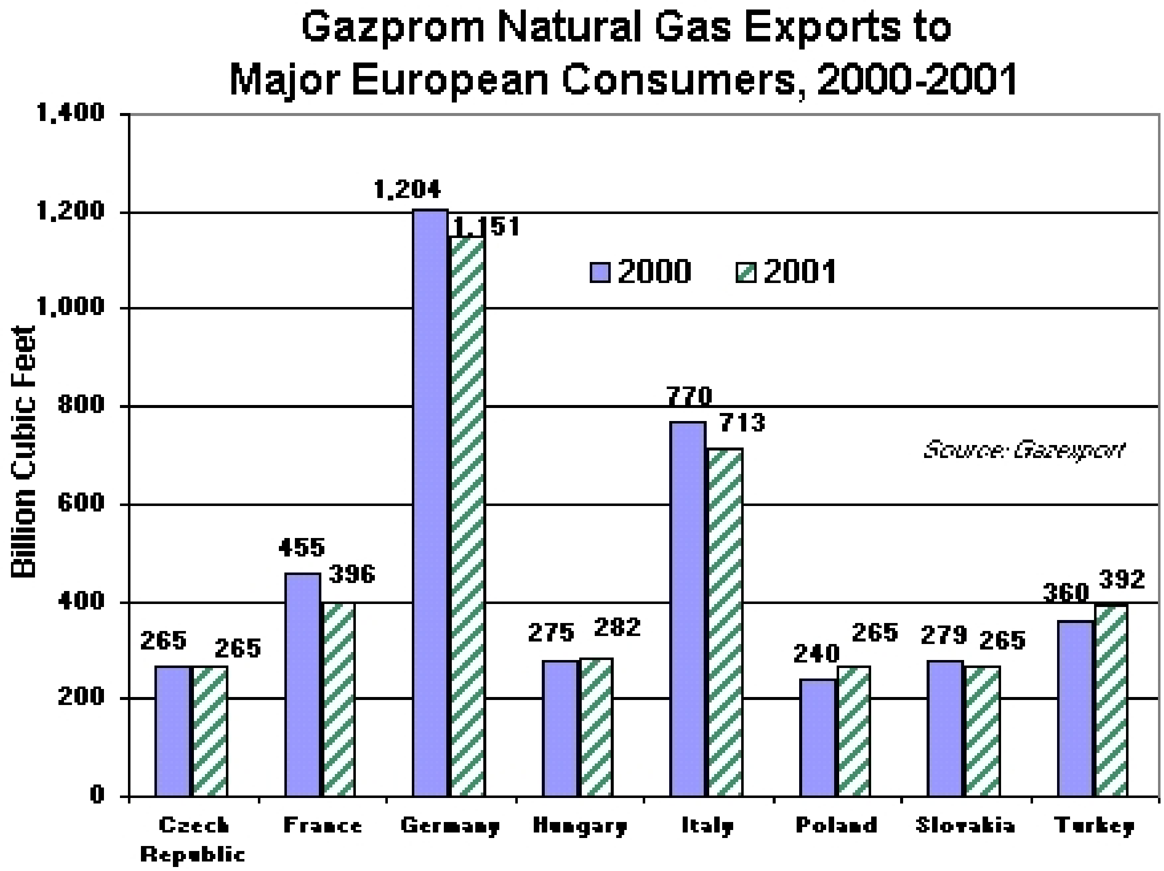
Russia has been relatively effective in reducing non-payments from the CIS by threatening to cut off natural gas supplies to debtors. After Itera, the Gazprom-linked gas trader that supplies Russian and Turkmen gas to Ukraine, threatened to cut off gas supplies to Ukrainian power generators unless Ukraine's debts were paid, Russia and Ukraine reached an agreement on Ukraine's natural gas debts in August 2001. In October 2001, the two sides ended the dispute with a 12-year deal restructuring some $1.4 billion of Ukraine's natural gas debts. Similarly, Russia periodically has cut off natural gas supplies to Georgia and Armenia over their debts for natural gas supplies.

To Europe

Between 1992 and 1999, Russian natural gas exports to non-CIS countries rose by 1.24 Tcf, from 3.14 Tcf in 1992 to 4.48 Tcf in 1999. Russian natural gas exports to Germany, Italy, and France all rose in 2000, when Russia exported 4.6 Tcf of natural gas to European consumers. Although that figure slipped to 4.48 Tcf in 2001, Russian natural gas exports to Europe now account for approximately 65% of Russia's total natural gas exports.

Russia supplies Europe with over 25% of its natural gas supplies, and with the energy accord signed by the EU and Russia in October 2000, Russia is seeking to increase this percentage. Gazprom, Russia's sole natural gas exporter to Europe, already has contracts to deliver 6.2-7.2 Tcf per year to Europe beyond 2007. However, if Gazprom is to fulfill this long-term aim of increasing its European sales, it will have to boost its production, as well as secure more reliable export routes to the region. Several proposed new export pipelines would serve European markets if constructed.

To Turkey
Russia already supplies Turkey with over 65% of its natural gas supplies, and that figure is set to jump in the fall of 2002 with the opening of the highly anticipated Blue Stream pipeline. The subsea pipeline, with a capacity of 565 Bcf, will provide a direct link across the Black Sea for Gazprom to supply the growing Turkish natural gas market. Although the pipeline is not yet completed, Russia is already increasing natural gas deliveries to Turkey via a pipeline running through Romania and Bulgaria.



To Asia
Russia is seeking to sell Siberian natural gas to China, and several natural gas pipelines to China are under consideration. Gazprom has been invited to bid on a $6-billion natural gas pipeline project in China, and the company also is considering building its own pipelines to sell Siberian natural gas to China and possibly South Korea. Additionally, several international natural gas projects on Russia's Sakhalin Island are planning to export natural gas to east Asia.

NATURAL GAS TRANSIT
Currently, Caspian region natural gas producers have few export options other than through Russia. Several new pipelines have been proposed, including a pipeline from Turkmenistan to Turkey, which would be routed across the Caspian Sea and then run via Azerbaijan and Georgia. However, Turkmenistan and Turkey have not been able to agree on a price for Turkmen natural gas, and the unresolved legal status of the Caspian Sea has hindered construction of such a pipeline bypassing Russia.

Turkmen Natural Gas Exports via Russia
Russia imports some Turkmen natural gas for its own consumption to supplement Russia's declining natural gas production, as well as re-exporting Turkmen natural gas as its own. In addition, the Turkmen natural gas supplied to Georgia, Ukraine, and Armenia currently crosses Russian territory.

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Caspian Sea Region: Oil Export Options

The collapse of the Soviet Union in 1991 opened up new opportunities for oil companies and international investors in the Caspian Sea region. The tremendous oil production potential in the Sea and the surrounding region has led to a boom in investment and fierce competition for exploration and development rights. During the Soviet era, oil exports from the Caspian Sea region were routed through Russia. Now that they are independent, Azerbaijan, Kazakhstan, and Turkmenistan, with the help of foreign investment, are seeking to increase their oil production and to diversify their export options. As oil from the Caspian region begins to flow in greater amounts, new pipelines will be needed to carry this oil from the Caspian to world markets.

Due to the Caspian region's relative geographical isolation, building new infrastructure to deliver the region's oil to consumers will be expensive. Geopolitical considerations, as well as the unresolved legal status of the Caspian Sea, are additional issues complicating the construction of export pipelines. Finally, several regional conflicts may prove to dissuade international investors from financing pipelines. Nevertheless, the region's bountiful oil production potential has meant that a number of Caspian oil export pipelines have been proposed. The United States has supported the principle of providing multiple export options for the Caspian's oil-producing countries, but it has discouraged export routes through Iran by enacting the Iran and Libya Sanctions Act.

West, to the Black Sea via Georgia

As part of the Eurasian Transport Corridor (TRACECA) transporting goods to Europe from the Caucasus, Georgia is set to become a major transit point for Caspian region oil.

Baku-Supsa

On March 8, 1996, Georgian President Eduard Shevardnadze and Azerbaijani President Heydar Aliyev signed a 30-year agreement to pump a portion of the "early oil" from the Azerbaijan International Operating Company (AIOC)'s production-sharing agreement in the Azeri, Chirag, and the deepwater portions of the Gunashli field through Georgia. The so-called "western route" for the AIOC early oil runs from Baku to the Georgian port of Supsa on the Black Sea.

The Georgian International Oil Company, a subsidiary of the AIOC, made substantial upgrades to the existing pipeline along this route and built the $565 million Supsa terminal on the Black Sea. The 515-mile, 100,000-bbl/d-capacity pipeline became operational in April 1999, with oil being pumped through Georgia at 18 cents per barrel. Officials from British Petroleum (BP), the operator of AIOC, said that the consortium exported approximately 130,000 bbl/d in 2001, with virtually all of its oil available for export being shipped to Supsa.

Recent upgrades have raised capacity on the Baku-Supsa pipeline to approximately 145,000 bbl/d. Proposals have been made to increase throughput along this route from the original design capacity of 100,000 barrels per day (bbl/d) to 300,000 bbl/d or even 600,000 bbl/d, but AIOC has focused its efforts on pushing ahead with the Baku-Ceyhan pipeline instead.

Rail and Smaller Pipeline Options
Oil from the Caspian region also could transit Georgia to its Black Sea ports via several smaller pipelines. Georgia already is playing a major role as a rail transit center for Caspian Sea oil, as it has been carrying oil from Azerbaijan and Kazakhstan by rail to its Black Sea ports since 1997.

Prior to the opening of the Caspian Pipeline Consortium's (CPC) Tengiz-Novorossiisk pipeline in the fall of 2001, ChevronTexaco had been delivering oil from the Tengiz field in Kazakhstan via the Caucasus. ChevronTexaco sent its oil across the Caspian by barge to the Dubendi terminal in Azerbaijan, where it was further transported via a pipeline to Ali-Bayramly (Azerbaijan), and then to Georgia's Black Sea port at Batumi in rail cars.

In September 1999, Chevron (now ChevronTexaco) and Georgian company Geoengineering signed an agreement on the preparation of a feasibility study for the reconstruction of the 105-mile pipeline from Khashuri to the port of Batumi, with an eye towards using the pipeline for transiting Tengiz crude. Together with an upgrade of the Batumi refinery, the project was estimated to cost $100 million.With the launch of the CPC, however, ChevronTexaco decided in May 2001 to cancel the project to reconstruct the Khashuri-Batumi pipeline, saying that the pipeline was economically unfeasible, especially since most of the Tengizchevroil exports are now routed via the CPC.

Nevertheless, Tengiz crude has been replaced at the Batumi port by high-quality Kumkol crude, supplied by Euro Asian Trading, and the lower-quality Buzachi blend, produced by Kazakhstan's Mangistaumunaigaz, both of which reach Batumi via a combination of barge, pipeline, and rail across the Caspian and the Caucasus. Turkmenistan also exports occasional cargoes of Cheleken and Okarem crude, which are mostly blended with the Kazakh oil either at the Batumi terminal or on barges, forming a "synthetic Urals" blend.

In order to accommodate more Caspian region oil transiting its territory, Georgia is upgrading its Black Sea ports and constructing new terminals. The Supsa and Batumi ports have been upgraded, and in May 2001, the EBRD agreed to finance the construction of a $20 million oil terminal at the Black Sea port of Poti. The Poti terminal will be able to handle up to 50,000 bbl/d, proving an alternative to the main port at Batumi.

In addition, Georgia and Turkey are working on plans to utilize a 172-mile railway line between Tbilisi and Kars, Turkey, to transport up to 200,000 bbl/d of crude oil from the planned Baku-Ceyhan pipeline to Turkish refineries. The railway plan, which could cost $400 million, will require refurbishing an existing line from Tbilisi to Akhalkalaki for $200 million, as well as extending the rail line 77miles to Kars.

West, to the Mediterranean Sea via Georgia and Turkey

In November 1999, Azerbaijan, Georgia, and Turkey signed agreements affirming the Baku-Ceyhan route as the Main Export Pipeline (MEP) for Azeri oil exports.

Baku-Ceyhan
The planned 1-million-bbl/d capacity, "Main Export Pipeline," which has received backing from the United States, will stretch approximately 1,038 miles (281 miles through Azerbaijan, 135 miles through Georgia, and 622 miles through Turkey) and is expected to cost between $2.8 billion and $2.9 billion to construct. Despite initial opposition to the pipeline, which several oil companies criticized as too costly and uneconomical with the planned volumes from Azerbaijan, construction on the Turkish section of the pipeline began in June 2002. The entire pipeline is expected to be finished in late 2004, with the first tanker leaving Ceyhan with Azeri oil in January 2005.

Despite earlier misgivings, BP, the operarator of the AIOC consortium that is expected to fill the pipeline, threw its support behind the Baku-Ceyhan proposal in 1999. BP had been opposed to the project, citing doubts that enough oil has been found to justify the high costs. However, BP revised downwards the amount of oil reserves that would be needed to make the pipeline economical, from 6 billion barrels to a more achievable 4 billion to 4.5 billion barrels.

Following the completion of a basic, 6-month engineering study in May 2001, the pipeline's sponsorship group, led by seven international oil companies and the State Oil Company of the Azerbaijan Republic (SOCAR), undertook a one-year, $150 million, detailed engineering feasibility study for the pipeline in Azerbaijan and Georgia (Turkish pipeline company Botas is responsible for the Turkish section of the pipeline). The detailed engineering study, covering all issues relating to the final details of the route, including the type of line pipe to be used, the pumps and pumping stations requirements, was completed in 2002.

Although construction on the Turkish section of the pipeline already has begun, financing for the Azeri and Georgian sections is still being arranged. Credits from international financial organizations are expected to finance 70% of the cost, with the remaining 30% coming from the pipeline sponsor group, which will become the Main Export Pipeline Company (MEPCO). Currently, seven of the ten members of the AIOC consortium are members of the sponsor group, with only Lukoil, ExxonMobil, and Devon Energy not members. SOCAR, which originally had a 50% stake in the sponsor group, sold ENI (Italy)--a non-member of AIOC--a 5% share in the pipeline project in October 2001.

After failing to come to agreement with other energy companies to join the sponsor group, in March 2002 SOCAR reduced its stake in the pipeline project to 25%, distributing 20% among other group members. In June 2002, SOCAR sold an additional 5% share to TotalFinaElf (France-Belgium), but rejected a proposal from ChevronTexaco to join the sponsor group. At the end of June 2002, the head of the sponsorship group, Michael Townshend of BP, said that the pipeline ownership group was complete. Shares in MEPCO are as follows: BP (38.21%), SOCAR (20%), Unocal (9.58%), Statoil (8.9%), TPAO (7.55%), TotalFinaElf (5%), ENI (5%), Itochu (3.4%), and Delta Hess (2.36%). .

North and Northwest, via Russia

Prior to the breakup of the Soviet Union, there was only one major crude export pipeline--the 240,000-bbl/d Atyrau-Samara pipeline from Kazakhstan to Russia--that connected Caspian Sea oil production to the Russian crude oil export pipeline system and world markets. However, the current proliferation of proposed export routes has put Russia in the position of having to compete with other export outlets for Caspian oil. Thus, Russia is looking to become a transit center for Caspian region oil. In June 2002, Kazakhstan and Russia signed a 15-year oil transit agreement under which Kazakhstan will export at least 350,000 bbl/d of oil annually via Russia, in addition to flows via the CPC.

Tengiz-Novorossiisk

In March 2001, the Caspian Pipeline Consortium (CPC) commissioned its $2.5 billion, 1.34 million-bbl/d-capacity pipeline, sending oil flowing 990 miles from Tengiz to Novorossiisk. After several customs problems and technical delays, the first oil was loaded onto a tanker in Novorossiisk in October 2001, and in November 2001, CPC shareholders decided on a transportation tariff of $26.32 per 1,000 tons ($3.59 per barrel) per 100 kilometers (62.5 miles). The CPC exported approximately 240,000 bbl/d in April 2002, with volumes expected to rise to 400,000 bbl/d by the end of 2002 once additional pumping stations and pipeline links are completed.

Preliminary plans are to increase exports to 520,000 bbl/d in 2003, but the pipeline is not scheduled to reach its full capacity until about 2015. ChevronTexaco, which operates the Tengizchevroil joint venture that currently is supplying the majority of to the pipeline, has estimated that during its 35 to 40 year expected life, the pipeline could bring in $8 billion in taxes for Kazakhstan, and development of the Tengiz field and operation of the pipeline would earn about $150 billion for Kazakhstan and Russia.

Since both Kazakh and Russian oil will be piped via the line, creating a new "CPC Blend" of oil, Kazakh and Russian officials created a "quality bank" to compensate higher-quality Kazakh oil exporters whose oil quality is diluted by the new blend. The Tengizchevroil joint venture will transport approximately 240,000 bbl/d via the pipeline in 2002, with future plans to export an additional 120,000 bbl/d per year via the pipeline from the Karachaganak field in Kazakshtan.

Turkey has raised concerns about the ability of the Bosporus Straits to handle additional tanker traffic that will be necessary to handle the planned volume of Kazakh oil to be exported via the CPC pipeline. Turkey has expressed its concern that the Straits, already a major chokepoint for oil tankers, cannot handle the strain of additional traffic, raising environmental concerns about a collision leading to an oil spill in the Straits. Although Kazakhstan has argued against limiting oil tanker traffic through the Straits, a number of "Bosporus bypass" options are under consideration or being developed in southeastern Europe. In addition, Ukraine already has constructed a new pipeline, the Odessa-Brody pipeline, specifically to transport oil from the Caspian Sea region to European markets.

Atyrau-Samara

In recent years, Kazakhstan's oil exports, which compete with Russian oil exports, have been limited by Kazakhstan's annual oil export quota through the Atyrau-Samara pipeline and the Russian pipeline system. (The CPC pipeline is not part of the Transneft-controlled Russian pipeline system.) With oil production in Kazakhstan on the rise, Kazakhstan is interested in gaining improved access to oil terminals in the Baltic Sea for its oil exports via the Atyrau-Samara pipeline. Although Kazakhstan has supplied a small amount of oil to Lithuanian terminals, deliveries have been delayed due to the lack of an agreement with Russia on transportation tariffs.

Since Kazakhstan now has an alternate oil export route via the CPC pipeline, Russian pipeline monopoly Transneft is looking to attract more Kazakh oil via the Atyrau-Samara pipeline. Russia recently completed an expansion of the 432-mile pipeline that increased its capacity to 310,000 bbl/d, and Russia has increased Kazakhstan's export quotas and lowered its pipeline tariffs. With the opening of Russia's new Baltic Pipeline System (BPS) in December 2001, Russia is keen to export Kazakh oil through its own Baltic Sea terminal at Primorsk. In an effort to fill the BPS and to profit from Kazakh oil transiting its territory, Russia allocated a 100,000 bbl/d quota of Kazakh oil for the BPS. The June 2002 transit agreement between Kazakhstan and Russia guarantees Kazakhstan the ability to pipe 300,000 bbl/d through the Atyrau-Samara pipeline.

Baku-Novorossiisk

The 100,000-bbl/d-capacity Baku-Novorossiisk pipeline, also known as the "northern route", opened in 1997. The pipeline runs 868 miles from Baku via Chechnya to the Russian Black Sea port of Novorossiisk. Initial exports through the pipeline were limited to approximately 40,000 bbl/d, however, owing to pumping limitations, disputes over transit tariffs, and the conflict in Chechnya. Up to 70,000 bbl/d of oil was forced to bypass Chechnya by rail from Dagestan to Stavropol.

The ongoing conflict and instability in Chechnya prompted Russian pipeline operator Transneft to construct a 120,000-bbl/d Chechnya pipeline bypass (160,000 bbl/d including rail links). In 2000, Azerbaijan's SOCAR committed itself to throughput of 46,000 bbl/d, but in the end only transported around 10,000 bbl/d, prompting Transneft to accuse Azerbaijan of not fulfilling its commitment to export oil along the bypass. In addition, the AIOC, which also was expected to export via Baku-Novorossiisk, has been reluctant to pipe its oil along this route, since it is longer and more expensive than the Baku-Supsa route, and also because the northern route mixes AIOC crude with other crude oils while in transit to Novorossiisk, reducing its value.

SOCAR exported approximately 50,000 bbl/d via the Baku-Novorossiisk route in 2001, and plans to maintain that rate in 2002. According to SOCAR, 2001 exports via the northern route increased because SOCAR refined 40,000 bbl/d less than in 2000; as Azerbaijan imported Russian natural gas, SOCAR significantly reduced production of fuel oil for local power stations and exported all of the surplus crude oil via the Baku-Novorossiisk pipeline. Russia says the the capacity on Baku-Novorossiisk can be increased to 300,000 bbl/d, but SOCAR will not have sufficient volumes to fill the pipeline, even at its present capacity, in the next few years.

A 1996 oil transit agreement between Russia and Azerbaijan is scheduled to terminate at the end of 2003, but the agreement will remain valid until one of the sides withdraws from it. Neither side is happy with the deal, however, and both sides want to resolve disagreements on oil quality, tariffs, and pumping volumes. For its part, Transneft wants to have a guaranteed amount of oil for several years in advance, so Russia has offered to pay for an increase in capacity in the Baku-Novorossiisk pipeline if Azerbaijan commits to shipping larger volumes of crude oil through the system over the long term.

SOCAR officials, on the other hand, are unhappy with the high tariffs and the absence of an oil quality bank for the Baku-Novorossiisk pipeline. SOCAR Deputy Chairman Ilham Aliyev has said that, due to differences in tariffs between the Baku-Supsa and Baku-Novorossiisk pipeline, Azerbaijan loses $13 million per every million tons (20,000 bbl/d) transported via the Baku-Novorossiisk route.

In addition, because the northern pipeline mixes high-quality Azeri Light with low-quality oil from other regions, Azeri oil exported via Novorossiisk is sold at a discount to Azeri oil exported via Baku-Supsa. Azeri officials would like to introduce an "oil quality bank" for the Baku-Novorossiisk pipeline, in which shippers who pipe low-quality oil via the pipeline would compensate Azerbaijan for the reduction in price of its high-quality Azeri Light at the pipeline's terminus. Currently, neither the Russian government nor the other exporters who use Baku-Novorossiisk compensate Azerbaijan for mixing their oils with Azeri oil and reducing its value.

Thus, with exports of 50,000 bbl/d in 2001, Aliyev estimated that Azerbaijan lost between $40 million and $50 million in added revenues by exporting via the Baku-Novorossiisk pipeline. Nevertheless, Russia insists that future Azeri oil should run to its port of Novorossiisk on the Black Sea, pointing out that Baku-Novorossiisk can be expanded and the transit costs via the pipeline could be a little as half the $3 per barrel that the proposed Baku-Ceyhan is expected to cost. However, future Azeri oil production, mainly from the AIOC, is slated to be exported via the Baku-Ceyhan pipeline.

Additional Export Options
In addition to the Baltic Pipeline System, Russia could export Caspian region oil to world markets via its pipeline system using Adriatic ports. By connecting the southern Druzhba pipeline with the Adria pipeline in Croatia, then reversing flows in the Adria, Russia could ship oil via the Croatian port of Omisalj, thereby allowing oil exporters to bypass the Bosporus Straits.

The Russian Transport Ministry also has proposed shipping oil via barge and tanker from Turkmenistan and Kazakhstan to Russian Caspian Sea ports such as Makhachkala and Astrakhan. From there, the oil could be sent by rail to the Russian ports of Novorossiisk and Tuapse on the Black Sea; Kazakh rail exports from the Tengiz oil field through Russia totaled approximately 100,000 bbl/d in 2000. The Transport Ministry said that total shipments from Turkmenistan could increase to 240,000 bbl/d as port facilities in Kazakhstan and Turkmenistan are upgraded and expanded. Turkmenistan is planning to export about 20,000 bbl/d via Makhachkala-Novorossiisk pipeline in 2002.

South, to the Persian Gulf via Iran
Iran has long maintained that routes through Iran to the Persian Gulf are the shortest and most economical for exporting oil from the Caspian Sea. In addition, the Persian Gulf routes would transport oil to Asia, where the demand for oil is projected to grow faster and command a higher price than the Mediterranean markets that most of the competing pipelines would serve.

Oil could be exported via Iran in two ways: by direct transportation by pipelines that pass through Iran en route to the Persian Gulf, or by oil swaps. However, any large investment in Iran's oil sector would be problematic due to direct U.S. economic sanctions and additional sanctions as dictated by the Iran and Libya Sanctions Act.

Oil Swaps
Iran has been promoting oil swaps via its proposed 370,000-bbl/d pipeline from its Caspian Sea port of Neka. Under this arrangement, oil will be shipped to Iran's Caspian Sea ports and transported via pipeline, rail, and tanker trucks to refineries located in northern Iran. In exchange, Iran would deliver a similar volume of crude oil to its Persian Gulf Coast, where Caspian exporters could ship their oil to consumers.

Under a 1996 agreement, up to 120,000 bbl/d of Kazakh oil was to be delivered by tanker via the Caspian Sea to the Iranian port of Neka, where it would travel by pipeline to a refinery at Tabriz to be refined and consumed locally. In exchange, Kazakhstan would receive a similar volume of crude ready for export at an Iranian port in the Persian Gulf. Kazakhstan and Iran have been trying to negotiate a supply deal for years, but previously Kazakh crude has proved incompatible with Iranian refineries and there have been disagreements over price.

Volumes also have been limited by contract and technical issues, including the initial problems by Iranian refineries in processing Kazakh crude oil. In the first quarter of 2002, Kazakhstan began making test deliveries to Neka of about 1,600 bbl/d. Kazakh officials hoped to increase the swaps to 17,000 bbl/d, but that appears to be unlikely at this time.

Turkmenistan increasingly has turned to swap agreements with Iran in order to export its oil, with Turkmen oil being delivered to the Iranian Caspian port of Neka. The oil swaps began in July 1998. Dragon Oil, which produced approximately 7,000 bbl/d in 2001 in a production-sharing agreement with Turkmenistan, has exported its share of this production through a swap deal with Iran since 1998, and in April 2000 the company signed a new 10-year swap agreement with Iran.

However, a major problem with swaps is the U.S. sanctions against Iran. U.S. economic sanctions on Iran have prohibited American oil companies with investments in the Caspian Sea region from participating in large-scale oil swaps with Iran; in April 1999, ExxonMobil's application for a license to swap Turkmen oil for Iranian oil was denied. The Iran-Libya Sanctions Act seeks to penalize non-U.S. firms from doing business with Iran, and as a result, it remains to be seen whether Kazakhstan and Turkmenistan will choose to increase swaps with Iran.

Kazakhstan-Turkmenistan-Iran
Several possibilities are available for direct transportation of Caspian oil to the Persian Gulf. One proposed pipeline would carry Kazakh oil via Turkmenistan to the middle of Iran, then connect to Iran's existing pipeline network and transport oil south to Iran's Persian Gulf ports. Iran has suggested that Azerbaijan also could transport its oil via this pipeline by shipping oil eastwards across the Caspian to the port of Turkmenbashi, Turkmenistan, where it could connect with the proposed Kazakhstan-Iran pipeline

In April 2002, Kazakh President Nursultan Nazarbayev, in a meeting with Iranian President Mohammed Khatami, stated that an oil pipeline route through Iran would be the most economical way to export Kazakh oil. Kazmunaigaz, the new Kazakh state oil and natural gas company, currently is in talks with TotalFinaElf to prepare a feasibility study for a pipeline from Kazakhstan to Iran. The proposed 900-mile, $1.2-billion pipeline would have a capacity of 1-million bbl/d.

Iran-Azerbaijan
Iran also has proposed a pipeline that would transport oil from Baku via a proposed 190-mile pipeline to northwest Iran, where it would connect with the existing Iranian pipeline network and refineries. TotalFinaElf, which has a large presence in Iran, has proposed building a pipeline with capacity of between 200,000 bbl/d and 400,000 bbl/d, and in May 2001, Iran's oil ministry authorized the construction of a refinery close to the Caspian sea near the border with Azerbaijan. However, Azerbaijan has indicated that progress on disputes with Iran concerning the division of the Caspian would need to occur before such a project moved forward, as well as Iranian progress towards improved relations with the West.

Southeast, to Pakistan via Afghanistan
Turkmenistan has signed a memorandum of understanding with Afghanistan and Pakistan to build a 1-million bbl/d pipeline to carry oil to Pakistan and world markets via Afghanistan. In October 1997, a tripartite commission comprising Afghanistan, Turkmenistan, and Pakistan was formed to start work on building the so-called "Central Asian Oil Pipeline" (CAOP).

However, no progress has made on the pipeline due to the instability in Afghanistan. Following the August 20, 1998, U.S. bombing raids on suspected Afghan strongholds of suspected terrorist Osama bin Laden, Unocal announced that it was suspending work on the pipeline, and in December 1998, it withdrew from the consortium formed to build the pipeline.

Since the Taliban government's ouster in December 2001, discussions regarding the Central Asian Oil Pipeline have resurfaced. U.S. Deputy Secretary of State Elizabeth Jones, during a January 2002 visit to Ashgabat, stated that the U.S. would support private companies that chose to undertake trans-Afghanistan pipeline projects if they were considered to be beneficial and commercially viable. Continuing unrest in Afghanistan has stalled any progress on the CAOP.

East, to China
Kazakhstan also is considering the Chinese market. Kazakhstan exported 50,000 bbl/d to China by rail in 1999, and Tengizchevroil has made test deliveries to China by rail. In June 1997, the China National Petroleum Corporation signed an agreement with Kazakhstan for a proposed $3.5 billion, 1,800-mile pipeline to China that would be financed by China. A feasibility study for the pipeline was undertaken, but the study was halted near its completion date. In order to make the project economically feasible, Kazakhstan would have to guarantee 500,000 bbl/d per year through the pipeline, a level to which Kazakhstan said it could not commit.

Trans-Caspian Sea Routes
The amount of oil that is sent by barge across the Caspian Sea is expected to rise further with expansions to pipeline, port, and rail infrastructure in Caspian region countries. In addition to the large volume of oil that already is being shipped by barge across the Sea, several trans-Caspian oil export pipeline options have been proposed.

As Caspian region production increases, trans-Caspian pipelines could bring increasing volumes of oil from Kazakhstan and Turkmenistan across the Caspian. The trans-Caspian pipelines would connect with other export pipelines from the Caspian region, such as the proposed Main Export Pipeline. Eventually, the cross-Caspian pipelines could be connected on the east with export routes flowing eastward as well. In December 1998, Royal Dutch/Shell, Chevron, and ExxonMobil signed an agreement with Kazakhstan to conduct a feasibility study for twin oil and natural gas pipelines that would pass across the Caspian Sea from Aqtau in western Kazakhstan to Baku.

However, the the idea of constructing trans-Caspian pipelines thus far has met with resistance. In addition to the legal issues relating to use of the Sea, Russia and Iran have raised environmental concerns about the impact of pipelines on the seafloor. Both countries have stated their oppostition to the laying of trans-Caspian pipelines on ecological grounds. Territorial disputes need to be resolved as well.

Oil Export Routes and Options in the Caspian Sea Region

Name/Location	Route	Crude Capacity	Length	Cost/Investment	Status
Atyrau-Samara Pipeline	Atyrau (Kazakhstan) to Samara (Russia), linking to Russian pipeline system	Recently increased to 310,000 bbl/d	432 miles	Increase in capacity cost approximately $37.5 million	Existing pipeline recently upgraded by adding pumping and heating stations to increase capacity.
Baku-Ceyhan ("Main Export Pipeline")	Baku (Azerbaijan) via Tbilisi (Georgia) to Ceyhan (Turkey), terminating at the Ceyhan Mediterranean Sea port	Planned: 1 million bbl/d	Approximately 1,038 miles	$2.9 billion	Detailed engineering study began June 2001. Construction scheduled to begin in 2002, with completion targeted for 2004.
Baku-Supsa Pipeline (AIOC "Early Oil" Western Route)	Baku to Supsa (Georgia), terminating at Supsa Black Sea port	Currently: 100,000 bbl/d; proposed upgrades to between 300,000 bbl/d to 600,000 bbl/d	515 miles	$600 million (before upgrade)	Exports began in April 1999; approximately 90,000 bbl/d exported via this route in 2000.
Baku-Novorossiisk Pipeline (Northern Route)	Baku via Chechnya (Russia) to Novorossiisk (Russia), terminating at Novorossiisk Black Sea oil terminal	100,000 bbl/d capacity; possible upgrade to 300,000 bbl/d	868 miles; 90 miles are in Chechnya	$600 million to upgrade to 300,000 bbl/d	Exports began late 1997; exports in 2000 averaged only 10,000 bbl/d.
Baku-Novorossiisk Pipeline (Chechnya bypass, with link to Makhachkala)	Baku via Dagestan to Tikhoretsk (Russia) and terminating at Novorossiisk Black Sea oil terminal	Currently: 120,000 bbl/d (rail and pipeline: 160,000 bbl/d); Planned: 360,000 bbl/d (by 2005)	204 miles	$140 million	Completed April 2000. Eleven-mile spur connects bypass with Russia's Caspian Sea port of Makhachkala.
Caspian Pipeline Consortium (CPC) Pipeline	Tengiz oil field (Kazakhstan) to Novorossiisk Black Sea oil terminal	Currently: 565,000-bbl/d; Planned: 1.34-million bbl/d (by 2015)	990 miles	$2.5 billion for Phase 1 capacity; $4.2 billion total when completed	First tanker loaded in Novorossiisk (10/01); exports rising to 400,000 bbl/d by end-2002

Central Asia Oil Pipeline	Turkmenistan and Afghanistan to Gwadar (Pakistan)	Proposed 1 million bbl/d	1,040 miles	$2.5 billion	Memorandum of Understanding signed by the countries; project stalled by regional instability and lack of financing.
Iran-Azerbaijan Pipeline	Baku to Tabriz (Iran)	Proposed 200,000 bbl/d to 400,000 bbl/d	N/A	$500 million	Proposed by TotalFinaElf.
Iran Oil Swap Pipeline	Neka (Iran) to Tehran (Iran)	175,000 bbl/d, rising to 370,000 bbl/d	208 miles	$400 million to $500 million	Under construction; oil will be delivered to Neka and swapped for an equivalent amount at the Iranian Persian Gulf coast.
Kazakhstan-China Pipeline	Aktyubinsk (Kazakhstan) to Xinjiang (China)	Proposed 400,000 bbl/d to 800,000 bbl/d	1,800 miles	$3.0 billion to 3.5 billion	Agreement 1997; feasibility study halted in September 1999 because Kazakhstan could not commit sufficient oilflows for the next 10 years.
Kazakhstan-Turkmenistan-Iran Pipeline	Kazakhstan via Turkmenistan to Kharg Island (Iran) on Persian Gulf	Proposed 1million bbl/d	930 miles	$1.2 billion	Feasibility study by TotalFinaElf; proposed completion date by 2005.
Khashuri-Batumi Pipeline	Khashuri (Georgia) to Batumi (Georgia)	Initial 70,000 bbl/d, rising to 140,000 bbl/d-160,000 bbl/d	Rail system from Dubendi, Azerbaijan, to Khashuri, then 105-mile pipeline from Khashuri to Batumi	$70 million for pipeline renovation	ChevronTexaco has canceled plans to rebuild and expand the existing pipeline.
Trans-Caspian (Kazakhstan Twin Pipelines)	Aqtau (western Kazakhstan, on Caspian coast) to Baku; could extend to Ceyhan	N/A	370 miles to Baku	$2 billion to $4 billion (if to Ceyhan)	Feasibility study agreement signed in December 1998 by Royal/Dutch Shell, ChevronTexaco, ExxonMobil, and Kazakhstan; project stalled by lack of Caspian Sea legal agreement.

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October 2001

Russia: Oil and Gas Export Pipelines

OIL PIPELINES

Russia has an extensive domestic oil pipeline system, with links to nearly all of the former Soviet republics. Transneft, the state-owned transport monopoly, manages, services, and is responsible for developing Russia's pipeline system. Russia's main export pipeline to Europe is the 1.2-million-bbl/d-capacity *Druzhba* (Friendship) pipeline that traverses Belarus before splitting into northern and southern routes and delivering oil supplies to customers throughout Europe.

However, aside from the Druzhba pipeline and the Novorossiisk export terminal on the Black Sea, Russia's ability to export its oil to world markets is limited. Since oil exports are a major source of revenue for Russia's budget, the country is seeking to increase its export capacity. Currently, Russia is building a number of new pipelines and export terminals, such as the Baltic Pipeline System, as well as increasing capacity at several existing terminals and pursuing plans to construct additional pipelines, including a major potential export pipeline to China.

Baltic Pipeline System

Outside of the Caspian Sea region, the Baltic Pipeline System (BPS) is Russia's largest new pipeline export scheme. This system involves the laying of a new main pipeline from Kharyaga (Nenets Autonomous District, Arkhangelsk region) to Usa (Komi Republic), the reconstruction of the Usa-Ukhta, Ukhta-Yaroslavl, and Yaroslavl-Kirishi pipeline segments, and the construction of a new pipeline from Kirishi to Primorsk and an oil terminal in Primorsk on the Gulf of Finland. The Baltic Pipeline System, which will export most of the oil from the Timan-Pechora and Western Siberia oil provinces, as well as some from Kazakhstan, will give Russia a direct outlet to northern European markets.

The first stage of the project involves the construction of the Primorsk oil terminal, the Kirishi-Primorsk pipeline section, and the reconstruction of the Yaroslavl-Kirishi section. Construction of the 162-mile Kirishi-Primorsk pipeline was completed in August 2001, and modernization of the Yaroslavl-Kirishi pipeline is ongoing. The Primorsk terminal, which will have an initial capacity of 240,000 bbl/d, is nearly complete, and the first tanker is scheduled to be loaded in Primorsk on December 27, 2001. The cost of the first stage of the project is estimated at $460 million. Oil companies paid $105 million in the form of a special rate for oil transportation, while the European Bank for Reconstruction and Development assigned $115 million in the form of a short-term credit. Transneft, Russia's monopoly pipeline operator, invested the remaining $240 million from its own funds.

Even before the first stage of the BPS is finished, Transneft says that construction of the second stage will start. The second stage, which is scheduled to take a year and a half to complete, involves the construction of a parallel pipeline and additional storage facilities in Primorsk that will increase the capacity of the BPS to 600,000 bbl/d. Over $20 million already has been allocated for the second stage, but at least $250 million is expected to be needed, and Russian Prime Minister Mikhail Kasyanov recently announced that the plan for financing the second phase of BPS had not been finalized. It is likely that a combined system involving loans drawn by Transneft and oil export tariffs will be used.

Transneft, which will be the sole owner and operator of the BPS, stands to earn approximately $400 million in revenues during the pipeline's first 20 years of operation. In addition, the opening of the Primorsk terminal will allow Russia to eliminate its dependence on exporting oil via Estonia, Latvia, and Lithuania, thereby saving Russia up to $1.5 billion per year in transit tariffs. However, despite the opening of the BPS, the projected increase in overall Russian oil exports may not decrease the amount of oil transiting the Baltic republics; as Russian oil companies ramp up their exports and fill the BPS, they will likely continue to export their oil via the ports in Ventspils, Butinge, and Tallinn in the Baltic republics.

China Oil Pipeline

In 2000, China imported just 29,000 bbl/d of crude oil directly from Russia, most of which was shipped via rail. In order to supply China's increasing oil demand and boost its own export potential, Russia has been negotiating with China to build an oil pipeline linking the two countries. In July 2000, Russian President Vladimir Putin and Chinese President Jiang Zemin signed a memorandum of understanding on a feasibility study for a potential oil pipeline between Russia and China.

In July 2001, Zemin signed an agreement with Russian Prime Minister Mikhail Kasyanov outlining the scope of the feasibility study for the pipeline. Transneft and Russia's second largest oil producer, Yukos, are working together on the idea of building the proposed $1.7-billion pipeline, which would bring Siberian oil to northeastern China. Under a 25-year deal, the pipeline would supply China with 400,000 bbl/d starting in 2005--the equivalent of 26% of China's projected net imports then. Spur lines would eventually link the Talakanskoye, Verkhne-Chonskoye, and Yurubchenskoye fields to the main pipeline, boosting capacity to 600,000 bbl/d by 2010 and helping to alleviate localized fuel shortages in Russia that have been aggravated by high rail tariffs.

The preliminary proposal signed by Chinese and Russian sides called for the line to stretch 1,400 miles from Angarsk, across Mongolia, then into Beijing. Russia wants to cut the pipeline's distance by traversing Mongolia, but China would like to circumvent Mongolia for security reasons. Discussions on choosing a final route for the pipeline are continuing, with construction slated for 2003.

Sakhalin Pipelines

Sakhalin Energy (Sakhalin-II),a consortium led by Royal Dutch/Shell (Netherlands/U.K.), has plans to build oil export pipelines to Japan, South Korea, and Taiwan by constructing nearly 480 miles each of oil and gas pipelines down the length of Sakhalin Island to the ice-free port of Prigorodnoye. The Sakhalin energy project currently produces oil in the six months of the year when the bitterly cold seas off the island's eastern shores are free of ice. Sakhalin Energy's plan is expensive, but will allow year-round oil and gas exports.

The rival Sakhalin-I group favors a shorter, 150-mile underwater pipeline. Sakhalin-I partners propose to export their oil across the Tatar Straits to DeKastri, on the Russian mainland, where an existing tanker terminal could be expanded to handle exports to Asia. It will be much cheaper to build, but off-takers will have to contend with ice for several months a year. Capacity of both the terminal and pipeline is planned at 240,000-300,00 b/d. Sakhalin-I says its export route will be cheaper than that of Sakhalin-II, but acknowledge that exports will not start before 2005.

CPC Pipeline

In March 2001, the Caspian Pipeline Consortium's (CPC) Tengiz-Novorossiisk pipeline was commissioned. The CPC pipeline, which is run by an international consortium rather than Transneft, has an initial capacity of 564,000 bbl/d, with throughput eventually increasing to 1.34-million bbl/d in 2015. Oil from the Tengiz field in Kazakhstan began to flow via the 990-mile pipeline to Russia's Black Sea port of Novorossiisk, but flows were suspended several times because the CPC did not have an agreement with Russia's State Customs Committee to transit Russian territory.

In June 2001, Russia and Kazakhstan signed an intergovernmental oil transportation agreement for 15 years, clearing the way for pumping on the CPC pipeline to resume. The first oil from the pipeline was scheduled to be loaded onto tankers in Novorossiisk on August 6, 2001, but continuing customs issues, as well as the lack of an "oil quality bank" to compensate for the different qualities oil that will be blended in the pipeline, further delayed the launch. With the oil quality bank now in place, the loading of tankers at Novorossiisk is now scheduled for early October 2001, with an official ceremony marking the event.

With a 24% stake, the Russian government is the largest shareholder in the Caspian Pipeline Consortium, but the lack of a pipeline linking the CPC pipeline with Russia's Transneft pipeline system currently prevents Russian oil from flowing through the CPC pipeline. As a result, the Chevron-led Tengizchevroil consortium looks set to be the only bidder for pipeline space in 2001 and 2002. Future inclusion of Russian crude will require Transneft to link its system to the CPC pipeline, as well as additional regulations or changes to the existing oil transit agreement and quality bank.

Sukhodolnaya-Rodionovskaya Pipeline

Transneft recently completed a 162-mile pipeline from Sukhodolny to Rodionovsky in the southern Rostov region, allowing oil headed south for the Russian Black Sea port of Novorossiisk to avoid transiting Ukraine. The 320,000-bbl/d line, which was put into operation in September 2001, removes the need for Russian oil exporters to use a 60-mile stretch of pipeline in Ukraine. The original, Soviet-era pipeline sidetracked west into Ukraine to serve the Lisichansk refinery, but after the collapse of the Soviet Union, Ukraine began charging Transneft high transit fees to use the pipeline. Transneft decided it was worth the $240-million cost to construct a bypass pipeline in order to avoid Ukraine's high transit fees.

Druzhba-Adria Integration
In October 2000, Yukos announced plans to integrate the Druzhba pipeline with the Adria pipeline, which runs from the Adriatic port of Omisalj in Croatia to Hungary. Yukos signed a $20-million agreement with Croatian oil transport company Jadranski Naftovod to modernize the Adria pipeline, which will help integrate the two pipelines and allow direct exports of Russian oil to the coast of the Adriatic Sea. However, flows from the Adria pipeline will need to be reversed in order to integrate the two pipelines.

GAS PIPELINES

Russia has a a comprehensive internal natural gas distribution system run by the state gas monopoly Gazprom, as well as a series of gas pipelines linking Russia to the former Soviet republics. Russia's main gas export pipelines to Europe run from West Siberia, across the Volga-Urals and Timan-Pechora, and through Ukraine and Belarus to Europe. The Brotherhood, Progress, and Soyuz gas pipelines, with capacities of 1 trillion cubic feet (Tcf) each, transit Ukraine, while the 1.0-Tcf Yamal-Europe I pipeline crosses Belarus, and the 0.8-Tcf Northern Lights gas pipeline transits both Belarus and Ukraine.

With world natural gas demand increasing, Russia is attempting to increase its capacity to export gas. In addition, with so many gas pipelines crossing Ukraine, Russia is seeking to build new pipelines to diversify its gas export routes (as well as pressure Ukraine to pay its gas debts to Russia). In order to reach lucrative markets in Western Europe and Asia, Russia is proceeding with the construction of a number of international gas pipeline projects, including the Blue Stream pipeline to Turkey, planning a bypass pipeline around Ukraine, and exploring gas markets in Asia.

"Blue Stream" Pipeline
Construction on the 565-Bcf "Blue Stream" twin gas pipelines from Russia to Turkey, via the Black Sea, officially began in February 2000. The section of the pipeline that is above ground is already completed, with Gazprom laying 222 miles of pipeline in Russian territory to the Black Sea coast at Tuapse, and Botas, the Turkish pipeline corporation, constructing a 300-mile long segment from Ankara to the Black Sea coast at Samsun. ENI (Italy) and Gazprom each have a 50% stake in the Blue Stream project.

In the spring of 2001, investigations into allegations of corruption in Turkey in the tendering for the Blue Stream pipeline set back the project. Turkey's Energy Minister, Cumhur Ersumer, was forced to resign after being named in a court indictment of 15 ministry officials charged with corruption. Aside from setting back the timetable for completion of the project, the Blue Stream pipeline itself was unaffected, and the last remaining hurdle to the realization of the pipeline is to lay 228 miles of pipeline beneath the Black Sea.

In August 2001, the Saipem 7000, an Italian technological innovation that is the only ship in the world capable of laying pipelines in up to 10,000 feet of water, began laying the pipeline at the bottom of the Black Sea at a depth of nearly 7,000 feet. ENI has stated that the first branch of the undersea pipeline will be completed by the end of 2001. In January 2002, the underwater part of the pipeline is to be connected to the dry land sections on the Turkish and Russian sides, and in March 2002, the first tests of the pipeline will be carried out. Thus, at the earliest, the first of two lines will come onstream in spring 2002, with a capacity of 282.5 Bcf per year, doubling to 565 Bcf/year when the second line opens.

Proposed Ukraine Bypass Pipeline

Currently, Ukraine transports over 90% of Russia's total natural gas exports to Europe. In return, Ukraine receives some 1 Tcf of gas from Gazprom in transit fees, which amounts to nearly 40% of the country's annual gas demand. Ukraine buys additional natural gas from Russia to meet its domestic demand. Ukraine has been delinquent in its payments to Russia for gas, racking up a debt that Moscow puts at $2 billion. In addition, Russia has accused Ukraine of siphoning off more gas than it has contracted for, threatening Russia's European customers with gas shortages.

Gazprom currently supplies around 25% of European gas demand, and is eager to increase its penetration in the region. Russian officials say that they need additional export routes to be able to meet Russia's increased gas supply obligations to the European Union (EU) now that they have concluded a long-term energy supply agreement. Thus, on October 31, 2000, Russian President Vladimir Putin announced that Gazprom and Gaz de France (France) had concluded a deal to construct a pipeline across Belarus, Poland, and Slovakia--bypassing Ukraine--that would ship Russian gas to consumers in Western Europe. A consortium of gas companies, including Ruhrgas and Wintershall (Germany), Gaz de France, and Snam/ENI (Italy), are undertaking a feasibility study for the line with Gazprom.

However, Poland has stated its hesitancy to host such a gas pipeline if it damaged Ukraine's interests. The agreements signed by the Polish and Russian governments in 1993 and 1995 anticipated the building of two lines of the Yamal-Europe gas pipeline through Polish territory. It was agreed where the first pipeline would enter Poland and where it would leave. The routing of the second was not agreed, although it was agreed that they did not have to run completely parallel and that it might veer southwest. The first pipeline was completed in September 1999, and construction on the second branch was supposed to have begun shortly thereafter.

Construction on Yamal-Europe II has not begun, but it appears that the pipeline may take a completely different route than expected since Gazprom's "Ukraine bypass" proposal would be an entirely new pipeline. The bypass pipeline would divert gas from crossing Ukrainian territory by linking to the existing Northern Lights pipeline in Belarus, then crossing instead into Poland. From Brzesc, Poland, the pipeline would run south to Velke Kapuszany in Slovakia, where there are big gas pumping plants with spare capacity. The 373-mile pipeline could have two lines with a maximum capacity of 2.1 Tcf per year, and would cost an estimated at $2 billion.

Repeated angry statements by Gazprom officials suggest that it was Russia's dispute with Ukraine over illegal siphoning of gas that made the Russian company think of sacrificing a shorter route through Ukraine and building alternative gas channels. The matter of Ukraine's theft of Russian gas became public in 1999 when Gazprom accused Ukraine of illegally siphoning off 1 Tcf of gas (worth $720 million at the price that Gazprom charges Ukraine) and re-exported 190 Bcf of it. Ukrainian officials admitted to taking more gas than they had contracted for, and pledged to end the practice. In December 2000, Russia and Ukraine reached a deal on Ukraine's gas debts, but in March 2001 Gazprom claimed Ukraine was continuing to siphon off Russian gas. A further agreement was reached in August 2001 with regard to Ukraine's gas debts, but Russia is continuing to look into a Ukraine bypass pipeline.

China gas pipelines

Russia also is looking to construct gas pipelines eastward to export gas to Asia. On September 29, 2000, Russia announced that it would expedite the development of eastern Siberia gas fields, as well as conduct a feasibility study for laying a natural gas pipeline to China in a bid to supply gas to China. Several international projects are seeking to deliver Russian gas to China, although China has narrowed it down to two major options: a BP (U.K.)-led consortium, Russia Petroleum, is that is developing gas from the Kovykta field, and the the Sakha consortium developing the Chayandinovskoye field. Analysts believe that only one pipeline will be needed.

The Chayandinovskoye option would cost approximately $6 billion-$10 billion and would entail a 1,700-mile pipeline link from the Chayandinskoye field to Xinjiang region northern China. In March 2001, Russia's Sakhaneftegaz and China's National Oil & Gas Development Corp. signed a preliminary agreement to develop the Chayandinovskoye field, which is estimated to contain 43 Tcf of gas, and build a dedicated pipeline with capacity of between 423 Tcf and 706 Tcf per year. Gazprom may act as the operator for the pipeline.

The second option for China to receive Russian gas is via a pipeline linking Irkutsk's Kovykta gas field with northeastern China. The Kovykta field, which is being developed by Russia Petroleum, a BP-led consortium, has estimated gas reserves of 49 Tcf. The pipeline would terminate in South Korea via a sub-sea pipeline across the East China Sea. The most direct route for the proposed Irkutsk pipeline--which Russia Petroleum strongly prefers--would be to pass via Mongolia into northern China and then down to South Korea.

However, China is urging that the pipeline bypass Mongolia and instead go around the eastern edge of that country and follow a route on to Manzhouli in northeastern China, then cross into North Korea before terminating in South Korea. China feels that a route across Mongolia would be geopolitically risky and argues that Mongolian gas demand does not justify having the pipeline cross its territory. If China insists that the pipeline not traverse Mongolia, an extra 700 miles will be added to the 2,000-mile pipeline route. In addition to the political issues related to the pipeline crossing North Korea, the added cost (from the extra length) of the pipeline may make the extension to South Korea unfeasible. Thus far, Russia Petroleum has failed to agree on the price China will pay for the gas. The project is now the subject of a feasibility study due to be completed early in 2002.

North TransGas
In late April 2001, Gazprom signed an agreement with Finnish and German customers for a feasibility study on a pipeline that would carry Russian gas across the Baltic Sea to serve Scandinavia and Germany. The North TransGas pipeline, if it is built, will be well located to handle gas production from the far north of European Russia and the Barents Sea, and also will allow Gazprom to avoid negotiating transit fees. Gazprom's partners in the North TransGas pipeline project are Finland's Fortum and Germany's Wintershall and Ruhrgas. Analysts believe that, with Gazprom's financial woes, only one of the proposed northern gas pipelines (the "Ukraine bypass" pipeline (Yamal-Europe II) or the North TransGas pipeline) is possible.

Japan Gas Pipeline
ExxonMobil (U.S.) and a consortium of Japanese firms are developing the Sakhalin I field jointly and proposing to deliver gas from the field to Japan. A 120-mile pipeline would run from the Sakhalin I field to Sapporo, on Japan's northernmost island of Hokkaido, and could be extended to Tokyo. A feasibility study for the pipeline is due to be completed in April 2002.

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www.eia.doe.gov Energy Information Administration

May 2002

Central Asia: Uzbekistan Energy Sector

UZBEKISTAN

Since Uzbekistan gained its independence in December 1991, the government has sought to prop up its Soviet-style command economy with subsidies and tight controls on production and prices. Although this gradualist reform strategy has helped the country to avoid the dramatic economic contraction and drastic decline in living standards recorded in many other countries in the Commonwealth of Independent States, thus far it has failed to bring about much-needed structural changes. While Uzbekistan has now recorded six straight years of real gross domestic product (GDP) growth, the lack of significant macroeconomic and structural reforms, the country's rapid accumulation of external debt, as well as its declining level of foreign exchange reserves, makes this pattern unsustainable.

The government continues to have a dominating influence on the Uzbek economy. Uzbekistan tightened currency and export controls in its largely-closed economy following the Asian and Russian financial crises, further deterring foreign investors already shying away from the country because of a poor investment climate and Uzbekistan's non-convertible currency, the som. Analysts argue that continuing administrative and trade controls are inhibiting export growth and discouraging foreign direct investment. Foreign investment in Uzbekistan is significantly lower than in other energy-rich former Soviet republics, such as Azerbaijan and Kazakhstan.

Oil

Uzbekistan is estimated to contain 594 million barrels of proven oil reserves, with 171 discovered oil and natural gas fields in the country. The Bukhara-Khiva region contains over 60% of Uzbekistan's known oil fields, including the Kokdumalak field, which accounts for about 70% of the country's oil production. In addition, the Fergana region contains another 20% of the country's oilfields, and the Ustyurt plateau and the Aral Sea have been targeted for further exploration. Oil deposits in Kokdumalak, Shurtan, Olan, Urgin and south-Tandirchi (all in southwestern Uzbekistan) are being developed rapidly.

As a result, despite a drop in oil production in the past few years, Uzbekistan has more than doubled its petroleum output in the past decade. From 65,500 barrels per day (bbl/d) in 1992, Uzbekistan increased its oil production to 161,000 bbl/d in 1998. Combined with the country's decrease in oil consumption (from 190,400 bbl/d in 1992 to 130,000 bbl/d in 2000), in 1996 Uzbekistan became a net oil exporter. However, Uzbekistan's oil and gas condensate production has been declining in the past few years as existing fields are exhausted faster than new commercial reserves are discovered. Uzbekneftegaz, the state oil and natural gas company, expects liquid hydrocarbon production in the country to fall to 120,000 bbl/d in 2005.

In an effort to stem the decline in Uzbekistan's oil production, the Uzbek government is seeking foreign investment in the country's oil sector. Uzbekistan is offering a 49% state in Uzbekneftegaz, the holding company that was created out of nine companies in 1998 to unite the country's entire oil and natural gas sector. Since independence, the Uzbek government has invested over $1.2 billion in modernizing Uzbekneftegaz, but the flow of money into the Uzbek upstream has been far slower than in other Central Asian nations due to Uzbekistan's strict currency controls.

Uzbekistan also is selling its 44% stake of Uzneftegazdobycha (Uzbekneftegaz's oil and gas exploration arm), 44% of Uztransgaz (oil and gas transport), 39% of Uzneftepererabotka (oil refining), and 39% of Uzburneftegaz (drilling company). This tender is part of an aggressive oil and natural gas investment bid launched by Uzbekistan on April 28, 2000, when President Karimov decreed that foreign companies involved in exploring and extracting oil and gas in Uzbekistan would receive tax exemptions and options to produce any oil or natural gas they discover within a set period of time.

The government is eager to attract $400 million through production-sharing agreements (PSAs) as well, with over 80 fields on offer. Of these, 78 of the fields are contained in 16 exploration blocks, and eight individual fields (with total remaining reserves of some 1.2 billion barrels of oil equivalent) have also been opened up for potential foreign participation. Those fields include four in the Southwest Gissar Basin (Dzharkuduk, Gumbulak, South Kizilbairak and South Tandircha) and four in the Amu Dar'ya region (North Shurtan, Shakarbulak, South Kemachi and Umid).

In addition, Uzbekistan is seeking investment to boost production at existing fields. Uzbekneftegaz already has teamed with oil services giant Baker Hughes in a joint venture to increase oil production at the country's North Urtabulak field to over 6,000 bbl/d. Baker Hughes, which will invest $8 million in the North Urtabulak project, also has the option to develop the Adamtash, South Kemachi, and Umid fields, with total investments of $120 million. UzPEC, a subsidiary of Britain's Trinity Energy, received licenses in 2001 to explore and develop oil and gas condensate fields in Southwest Gissar and Central Ustyurt. According to its PSA with Uzbekneftegaz, UzPEC will hold the licenses for 40 years and will be required to invest more than $400 million, including $200 million in the next five years.

Downstream/Refining

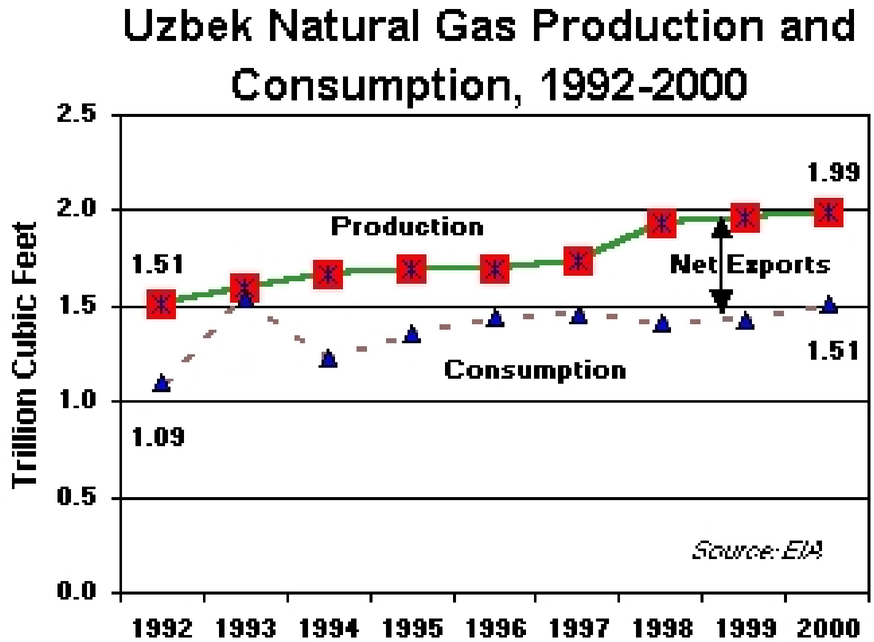
Uzbekistan has three refineries, at Fergana, Alty-Arik, and Bukhara, with a total refining capacity of 222,000 bbl/d. The Bukhara refinery, which was the first refinery built in the Commonwealth of Independent States since the breakup of the Soviet Union and cost in excess of $400 million, currently has a capacity of 50,000 bbl/d, although it is expected to expand to 100,000 bbl/d and refine both crude oil and gas condensate. Due to the country's decline in oil production in 2001, Uzbek refineries operated well below-capacity during the year. Uzbekistan's limited refined product exports move by rail and road to neighboring countries and to export ports on the Black Sea.

Along with joint ventures with foreign investors, Uzbekistan is looking to refinery modernization as a crucial component of the country's strategy to attain self-sufficiency in oil. In 1996, Texaco (now Chevron Texaco, U.S.) and Uzneftepererabotka formed the UZ-Texaco joint venture at the Fergana refinery to produce and market Texaco-branded engine, transmission, and hydraulic lubricants from local crude oil. In 2001, Mitsui (Japan) completed a $200-million reconstruction at the Fergana refinery to expand desulfurization capacity at the refinery.

Natural Gas

With estimated natural gas reserves of 66.2 trillion cubic feet (Tcf), Uzbekistan is the second largest natural gas producer in the Commonwealth of Independent States (after Russia) and one of the top ten natural gas-producing countries in the world. Uzbekistan produces natural gas from 52 fields in the country, with 12 major deposits--including Shurtan, Gazli, Pamuk, Khauzak--accounting for over 95% of Uzbekistan's natural gas production. These deposits are concentrated in two general areas: the Amu Dar'ya Basin and in the Mubarek area of the southwest part of the country.

Since becoming independent, Uzbekistan has increased its natural gas production by over 30%, from 1.51 Tcf in 1992 to 1.99 Tcf in 2000. According to preliminary 2001 data, Uzbek natural gas production increased to 2.03 Tcf for the year. However, Uzbekistan's natural gas fields were heavily exploited in the 1960's and 1970's by the Soviet Union, and as a result several older fields, such as Uchkyr and Yangikazgan, are beginning to decline in production. In order to offset those declines, Uzbekistan is speeding up development at existing fields, such as Garbi and Shurtan, as well as developing new fields and exploring for new reserves. The Shurtan field, which began producing in 1980 and is the second biggest in the country after Gazli, accounted for approximately 36% of Uzbekistan's total natural gas output in 2000.



Due to its high sulfur content, the majority of Uzbekistan's natural gas requires processing before it can be consumed. Much of Uzbekistan's natural gas is processed at the Mubarek processing plant, which has a capacity of over 1 Tcf/year. In December 2001, Uzbekneftegaz commissioned the Shurtan Gas-Chemical Complex, which includes installations to clean natural gas, a natural gas booster compressor station, and a plant with the capacity to produce 125,000 tons of polyethylene and 137,000 tons of liquefied natural gas per year. The complex, which is located by the Shurtan gas fields in the southwest part of the country in the Kashkadar'ya Region, was completed at a cost of $1 billion.

In addition to the Shurtan project, Uzbekneftegaz is undertaking several projects to ensure the country's natural gas sector will remain vibrant. The company's Kodzhaabad underground natural gas storage facility in Andizhan Region opened in 1999 at a cost of $72 million, allowing increased natural gas shipments to Uzbekistan's industrial heartland in the Fergana Valley. In January 2001, Trinity Energy (U.K.) committed to investing more than $400 million, over a 40-year period, in exploration and production of gas condensate deposits in the Plato Ustyurt region.

In March 2002, Russia's Itera and Lukoil signed a PSA with Uzbekneftegaz to form a joint-stock company to develop several new gas fields in Uzbekistan, including the giant Kandym field. Natural gas reserves at the fields covered by the PSA are estimated at 8.1 Tcf, including approximately 5.4 Tcf at the Kandym structure. Initial investments in the project are estimated at $377 million, with natural gas production rising from 159 billion cubid feet (Bcf) per year to between 280 Bcf and 350 Bcf per year at its peak. Itera and Lukoil each will hold 45% shares in the company, with Uzbekneftegaz keeping a 10% stake in the project.

Coal

Uzbekistan has estimated coal reserves of 4.4 billion short tons, the majority of which are located in just three deposits. Approximately 75% of Uzbekistan's coal reserves are lignite and subbituminous brown coal. The Angren lignite coal field, which is in the Tashkent region and is the country's largest coal deposit, holds a proven 1.9 billion tons of commercially recoverable brown coal. In 2000, Ugol, the Uzbek national coal company, produced 3.2 million short tons (Mmst) of coal, 90% of which came from the Angren mine. In the first nine months of 2001, Ugol produced 2.65 Mmst of coal, a 3.5% increase over the same time period in 2000.

Uzbekistan's domestic coal consumption has declined by 50% in the past decade--from 6.4 Mmst in 1992 to 3.2 Mmst in 2000--making Uzbekistan a net coal exporter, despite the country's drop in coal production from 5.1 Mmst in 1992. In order to increase coal production, the Uzbek government is implementing a program to update the country's coal sector by modernizing production facilities. In 2001, Krupp Fordertechnik GmbH (Germany) won a tender to refurbish the Angren coal mine, a project that will be implemented over 10 years in six stages. The project stipulates a transition from cyclical coal extraction technology to the flow-line method, which Uzbek officials hope will raise coal extraction to 5 Mmst/year and will cut production costs at Angren from $23/ton to $12/ton.

Ugol plans to upgrade mining operations at its other main deposits as well. The Shargun and Baisun deposits, both of which are located in the Surkhandarya region, are much smaller than the one at Angren. Additional investment at the Shargun deposit is expected to double or triple production of high-quality coal from current levels of over 200,000 short tons/year. Completion of a second mine at Baisun could quintuple the mine's production of over 100,000 short tons/year, and could ensure that Uzbekistan has a surplus of coal for export in the future.

Electricity

Uzbekistan has 37 power stations, with a combined installed generating capacity of 11.7 gigawatts (GW). Much of Uzbekistan's electric power is generated from natural gas-powered plants, with smaller amounts generated from coal and hydroelectric facilities. The largest natural gas-fired plants are the Syr Dar'ya (3,000 megawatts, MW) and Navoi (1,250 MW) plants, which together account for over one-third of the entire country's generating capacity. Several coal-powered facilities, including the 1,800-MW coal-fired Angren plant, are located near the Angren mine near Tashkent, while 25 small hydroelectric plants (the 620-MW Charvak station is the largest) supply almost 15% of Uzbekistan's electricity.

Uzbekistan generated 44.1 billion kilowatt-hours (Bkwh) of electricity and consumed 41.9 Bkwh in 2000. Nevertheless, owing to significant line losses in the country's deteriorating power infastructure, much of the electricity that Uzbekistan generates never reaches customers. As a result, Uzbekistan is actually a net electricity importer. However, the Uzbek government has developed a plan to increase the country's electric-generating capacity by attracting foreign capital and loans to reconstruct and upgrade a number of Uzbek power plants.

In December 2001, Germany's Siemens completed reconstruction of the first of two power-generating units at the Syr Dar'ya Power Plant, with the second unit scheduled to be finished early in 2002. The modernization of two of the 10 units at the Syr Dar'ya Power Plant will increase the plant's power-generating capacity by 600 MW to 3,600 MW. Uzbekistan's plans also call for the modernization of Unit 1 at the Talimardjan Power Plant, as well as the construction of new units to increase the plant's installed capacity to 3,200 MW.

In March 2002, Uzbekenergo, the state power company, announced plans to call for an international tender later in 2002 to reconstruct the 1,860-MW Tashkent State Regional Power Plant. The $221-million project will include the construction of a new power-generating unit with a 370-MW steam gas turbine. The reconstruction will take 28 months, according to a feasibility study for the project prepared in 1999 by Japan's Mitsubishi Corporation and approved by the Uzbek government.

Uzbekistan also is attempting to attract foreign investment to revamp electric power systems and stations in Navoi, Mubarek, and other cities, as well as to modernize the electric power grid in Tashkent. ABB Lummus has begun a feasibility study of a $60-million project to rebuild the heat and power plant in Mubarek, increasing its capacity from 60 MW to 100 MW, and in January 2002, ABB signed a $17.4 million contract with Uzbekenergo on the construction of two electricity substations in Tashkent, as well as connections to the grid.

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Energy Information Administration

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Central Asia: Kyrgyzstan Energy Sector

KYRGYZSTAN

Despite some progress in implementing economic reforms, Kyrgyzstan remains one of the poorest countries of the former Soviet Union. Kyrgyzstan's economy contracted sharply in the early 1990s, and while foreign assistance played a substantial role in the country's economic turnaround in the mid-1990s, Kyrgyzstan suffered severe economic aftershocks from the August 1998 financial crisis in Russia. The Kyrgyz government has enacted a number of measures to combat the country's economic problems, including efforts to stabilize rampant inflation, boost stagnant industrial production, and stimulate growth.

In 2001, Kyrgyzstan's inflation rate was reduced to 5.3% (down from 39.9% in 1999) and its real gross domestic product (GDP) grew 6.6%. Still, the country's nominal GDP in 2001 was just $1.5 billion, meaning that per capita annual income in the country of 5 million people is approximately $290. President Askar Akayev, formerly praised by the West for his market reforms, was re-elected to a third term in office in October 2000 with 74% of the popular vote in an election in which the main opposition candidates were prevented from running.

Oil

With estimated petroleum reserves of only 40 million barrels, Kyrgyzstan is reliant on imports to meet its domestic supply needs. Kyrgyzstan has seven developed oil fields and two oil/gas fields, but due to the country's mountainous topography, extraction is difficult, and water encroachment means that recovery rates are low. In 2000, Kyrgyzstan produced an estimated 2,100 barrels per day (bbl/d) of oil. Although the country's oil consumption has declined sharply since 1992, when it consumed 32,500 bbl/d, Kyrgyzstan's estimated oil consumption in 2000 of 12,000 bbl/d still required imported supplies to meet domestic demand.

Kyrgyzstan is looking to increase its oil production, and the government is undertaking a program of intensive oil extraction in order to meet the country's domestic petroleum needs. Oil reserves in the Fergana Valley are estimated at 733 million barrels, while 200-300 million tons (1.47-2.12 billion barrels) are thought to be deposited in the Chuy, Alay, Issyk-Kul, and At-Bashi depressions. Under the program to develop the country's oil sector, Kyrgyzstan is planning to produce 3,000 bbl/d by 2005.

In an effort to reach that target, Kyrgyzneftegaz, the state oil and natural gas company, is partnering with several foreign energy companies, as well as the Chinese government. A Kyrgyz-Austrian joint venture with Kyrgyzneftegaz and Action Hydrocarbons spent approximately $5 million on exploration work in 2001, and this may increase to $30 million in 2002. In addition, Chinese and Kyrgyz specialists are repairing more than 100 idle oil wells in Kyrgyzstan in 2002. Kyrgyzneftegaz also is planning to begin drilling exploration wells in the Dzhalalabad region in 2002, investing $30 million of its own money.

Downstream/Refining

Kyrgyzstan has one crude oil refinery, in Dzhalalabad, about 150 miles south of Bishkek. The refinery, which was built in 1997, is run by the Kyrgyz Petroleum Company, a joint venture between Kyrgyzneftegaz, the country's state-owned oil company, and Petrofac Resources International Ltd. (U.K.), which bought its share from Canadian-based Kyrgoil in June 2000. The 10,000-bbl/d-capacity refinery produces heavy fuel, diesel, and gasoline, but it has been hamstrung by difficulties in getting reliable supplies of crude oil from neighboring countries, especially Kazakhstan, amid the region's economic and political disorder.

A Kyrgyz-Kazakh joint venture, Bigmao Oil, is in the process of building a 400 bbl/d-capacity mini refinery for fuel oil in Kyrgyzstan. Abylaikham Group holds 50%, Kyrgyzneftegaz holds 25%, and private investors hold 25% of the refinery, which will begin operating by end-2002.

Natural Gas

Kyrgyzstan has proven natural gas reserves of 200 Bcf. The country's natural gas sector is small, and domestic natural gas production has declined from 3.5 billion cubic feet (Bcf) per year in 1992 to only 0.5 Bcf in 2000. As a result, Kyrgyzstan is heavily dependent on natural gas imports, mainly from Uzbekistan, to meet its domestic consumption requirements (67.5 Bcf in 2000). Kyrgyzstan receives natural gas from Uzbekistan under agreements signed by Kyrgyzgaz, the state's natural gas distribution company, and Kyrgyzenergo, the state electric utility.

Since Uzbekistan began charging higher rates for its natural gas in the mid-1990s, Kyrgyzstan has fallen into payment arrears, and Uzbekistan periodically has cut off natural gas to Kyrgyzstan in response. While much of Kyrgyzstan's electricity is generated by hydropower in the warmer months of the year, natural gas is the primary fuel used in heating Kyrgyz cities and villages, as well as in electricity generation during winter. Thus, winter supply disruptions to Kyrgyzstan have resulted in blackouts and heating shortages. Kyrgyz and Uzbek officials have negotiated several barter deals to exchange Kyrgyz electricity, water, and/or goods for Uzbek natural gas, but these deals have often fallen through, causing tension between the neighboring states.

Coal

Kyrgyzstan's small coal industry includes 11 mines. From 1992 to 1999, the country's production and consumption of coal were on the decline, but both rebounded in 2000, with Kyrgyz coal production amounting to 0.7 million short tons (Mmst) while coal consumption totaled 1.7 Mmst. In addition, Kyrgyzkomur, the country's major coal producer, reportedly boosted its coal production by 12% in 2001, with additional increases forecast for 2002. Under a government program passed in 1998 to develop the coal industry, Kyrgyzstan's coal production should be increased to 1.085 Mmst per year by 2005.

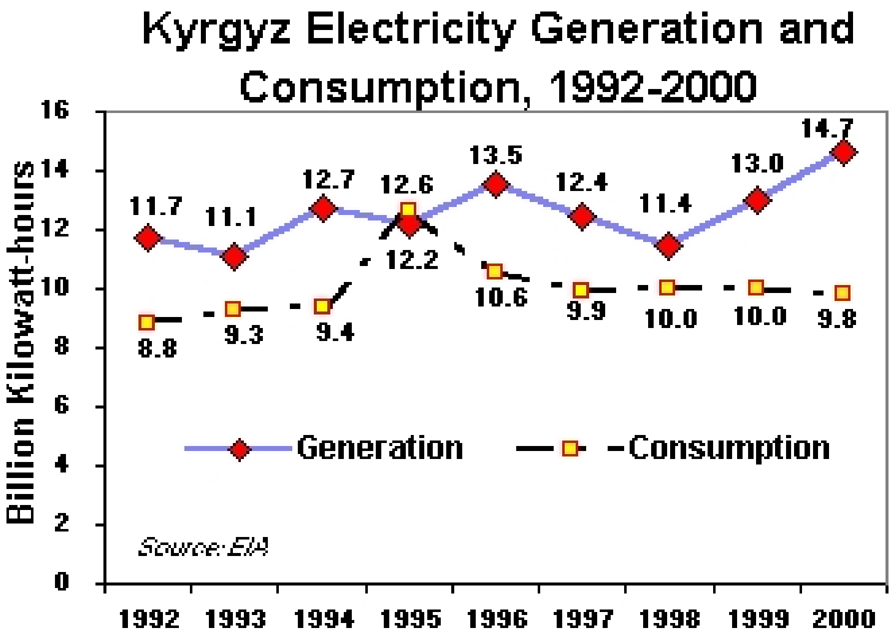
A 1999 report for Kyrgyzstan's Ministry of Foreign Trade and Industry suggested that the country could overcome its coal deficit by exploiting the Kara-Keche deposit in the Narynsk Region, one of Kyrgyzstan's 70 coal deposits. Although the Kara-Keche deposit would yield high-quality coal, high extraction costs and a lack of equipment have hindered development of the deposit. Analysts have estimated the cost of developing the Kara-Keche deposit at $52 million. The Kyrgyz government is seeking a strategic investor to develop the deposit, and is studying a comprehensive plan to invest in Kara-Keche as proposed by Tekhmashimpex.

Electricity

Kyrgyzstan's electric power industry is capable of meeting the country's domestic electricity needs while providing surplus electricity for export. Kyrgyzstan has two major electric power plants--a 1.2-gigawatt (GW) hydropower plant at Toktogul, and a 0.76-GW thermal plant at Bishkek, with plans for a major 6.8-GW hydropower station to be built by 2010. In 2000, Kyrgyzstan generated 14.7 billion kilowatt-hours (Bkwh) of electricity, up from 13.0 Bkwh in 1999, while the country consumed only 9.8 Bkwh in 2000.

Kyrgyzstan's abundant water resources give it significant hydroelectric potential. The energy potential of Kyrgyzstan's mountain rivers is estimated at 163 Bkwh per year, of which only about 10% is currently exploited. Hydroelectric energy meets approximately 20% of Kyrgyzstan's primary energy requirements and accounts for nearly 20% of its total exports. With rapidly growing energy demand in neighboring countries, Kyrgyzstan's hydroelectric power potential is becoming more attractive to foreign investors. The long-delayed 450-megawatt (MW) Tash Kumyr Hydroelectric Plant was put into full operation in 2001, and Kyrgyzstan is working to secure financial resources to construct two power-generating units at the Kambar-Ata Hydroelectric Plant.

Although Kyrgyzstan has excess electricity generation, up to one-third of the power that the country generates is lost due to Kyrgyzstan's deteriorating power infrastructure. A lack of transmission-related equipment and inadequate pricing and cost recovery have contributed to problems in the power sector. The Kyrgyz government allowed Kyrgyzenergo to raise electricity tariffs in March 2002 in an effort to recoup generation costs, but already more than half of residents in the Kyrgyz capital are not able to pay because of previous rate increases.



Since the country's major hydroelectric power stations are located in the south, the north of the country typically depends on supplies of Kazakh electricity in the winter. After Kazakhstan withdrew from the Central Asian power grid in early 2002, northern Kyrgyz districts were left with insufficient electricity, prompting Kyrgyz government official to ask residents in the north to conserve electricity.

Besides the irregular natural gas supplies from Uzbekistan, Kazakhstan's decision to leave the regional power grid has given Kyrgyzstan additional incentive to shore up its power system. Kyrgyzstan already has embarked on a program to make the country self-sufficient in energy by 2005, seeking to increase its electric installed capacity and to modernize its distribution system. Kyrgyzstan has borrowed money from international development banks to build substations, the Alai-Batken, Kemin-Naryn, and Naryn-Torugart power lines, to rehabilitate/reconstruct heat and power grids and the Bishkek heat and power plant, and to buy equipment.

In 2001, Kyrgyzstan embarked on a restructuring of Kyrgyzenergo, splitting off the company's distribution networks and leaving the former monopoly as just an electricity generating company. Four joint-stock companies--Sever Elektro, Vostok Elektro, Osh Elektro, and Dzhalalabad Elektro--were created from Kyrgyzenergo in the different regions of the country. However, the new companies are still saddled by their own debts to Kyrgyzenergo and by consumers' failure to pay their electricity bills. Kyrgyzstan plans to privatize these regional electricity distribution companies as the next step in the reform process.

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April 2002

Russia: Oil and Natural Gas Export Pipelines

OIL PIPELINES

Russia has an extensive domestic oil pipeline system, with links to nearly all of the former Soviet republics. Transneft, the state-owned transport monopoly, manages, services, and is responsible for developing Russia's pipeline system. Russia's main export pipeline to Europe is the 1.2-million-bbl/d-capacity *Druzhba* (Friendship) pipeline that traverses Belarus before splitting into northern and southern routes and delivering oil supplies to customers throughout Europe. The northern Druzhba line runs from Russia via Belarus to Poland and on to eastern Germany, while the southern Druzhba line cuts across northern Ukraine and on to Hungary, Slovakia, and the Czech Republic.

However, aside from the Druzhba pipeline and the Novorossiisk export terminal on the Black Sea, Russia's ability to export its oil to world markets is limited. With the breakup of the Soviet Union, Russia 's main export terminals for crude oil and oil products--in Ventspils (Latvia), Klaipeda (Lithuania), Tallinn (Estonia), and Odessa (Ukraine)--were located outside Russia's borders, forcing the country to pay transit fees to its neighbors in order to export its oil.

Since oil exports are a major source of revenue for Russia's budget, the country is seeking to increase its domestic export capacity and reduce the fees it pays to transit countries. Thus, Russia is building a number of new pipelines and export terminals, such as the Baltic Pipeline System, as well as increasing capacity at several existing terminals and pursuing plans to construct additional pipelines, including a potentially major oil export pipeline to China.

Baltic Pipeline System

Outside of the Caspian Sea region, the 284-mile Baltic Pipeline System (BPS) is Russia's largest new pipeline export scheme. This system involves the laying of a new main pipeline from Kharyaga (Nenets Autonomous District, Arkhangelsk region) to Usa (Komi Republic), the reconstruction of the Usa-Ukhta, Ukhta-Yaroslavl, and Yaroslavl-Kirishi pipeline segments, and the construction of a new pipeline from Kirishi to Primorsk and an oil terminal in Primorsk on the Gulf of Finland. The first stage of the BPS, with an export capacity of 240,000 bbl/d, was put into operation in December 2001 when the first tanker was loaded at Primorsk. The cost of the first stage of the BPS has been estimated at $460 million.

The BPS, which will export most of the oil from the Timan-Pechora and West Siberian oil provinces, as well as some oil from Kazakhstan, gives Russia a direct outlet to northern European markets, allowing the country to reduce its dependence on transit routes through Estonia, Latvia, and Lithuania. Use of the BPS, which is fully owned and operated by Transneft, the Russian pipeline monopoly, should bring the Russian government $100 million per year in fees, as well as allow Russia to save up to $1.5 billion each year in transit tariffs. In addition, Russian officials argue that the oil-loading terminal in Primorsk also allows Transneft to maneuver between southern and northern export routes, giving exporters greater flexibility and attracting more oil from the Caspian Sea region to transit Russia.

Transneft President Semyon Vainshtok announced in November 2001 that construction of the second stage of the BPS will begin in June 2002. The second stage of the BPS, which will take a year and a half to complete, will involve construction of three pump stations and eight storage tanks, as well as upgrades to the Yaroslavl-Kirishi pipeline. The cost of the second stage of construction, which will increase the capacity of the BPS to 360,000 bbl/d, is estimated at around $350 million to $400 million.

However, the BPS has already run into problems. In January 2002, Transneft pumped an average of 236,000 bbl/d through the BPS, nearing its capacity, but in February 2002, Finnish energy company Fortum, which purchased nearly one-third of the BPS exports in January, cut its orders by 85%. After ordering an average of 72,300 bbl/d for the month in January 2002, Fortum reduced its purchases from the BPS to an average of just 10,845 bbl/d in February, citing high levels of sulfur that entered the BPS in the Udmurtia and Bashkortostan republics, making it more expensive to process on delivery in Finland. Most of the oil that was pumped through the BPS in January 2002 came from came from Sibneft, Lukoil and Surgutneftegaz.

China Oil Pipeline

In order to supply China's increasing oil demand and boost its own export potential, Russia has been negotiating with China to build an oil pipeline linking the two countries. In July 2000, Russian President Vladimir Putin and Chinese President Jiang Zemin signed a memorandum of understanding on a feasibility study for a potential oil pipeline between Russia and China, and in September 2001, Russian and Chinese officials signed a general agreement to prepare a feasibility study for the construction of a Russia-China oil pipeline.

Originally, Transneft and Russia's second largest oil producer, Yukos, were working together on the idea of building the proposed $2.5-billion pipeline, which would bring East Siberian oil to northeastern China. Under a 25-year deal, the pipeline would supply China with 400,000 bbl/d starting in 2005--the equivalent of 26% of China's projected net imports then. Spur lines would eventually link the Talakanskoye, Verkhne-Chonskoye, and Yurubchenskoye fields to the main pipeline, boosting capacity to 600,000 bbl/d by 2010 and helping to alleviate localized fuel shortages in Russia that have been aggravated by high rail tariffs.

The preliminary proposal signed by Chinese and Russian sides called for the line to stretch 1,400 miles from Angarsk, across Mongolia, then into Beijing. Russia wants to cut the pipeline's distance by traversing Mongolia, but China would like to circumvent Mongolia for security reasons. In addition, Yukos and Transneft have differed in their preferences for the pipeline route, with Yukos, which previously favored a pipeline route from its fields in the Tomsk region straight to China, now favoring a route that would terminate in Nakhodka on Russia's Pacific Ocean coast. Yukos argues that shipping crude via Nakhodka would give producers a bigger choice of buyers, while Transneft has said that both routes could eventually be built. Discussions on a final route for the pipeline are continuing.

Sakhalin Pipelines
Sakhalin Energy (Sakhalin-2), a consortium led by Royal Dutch/Shell (Netherlands/U.K.), has plans to build oil export pipelines to Japan, South Korea, and Taiwan by constructing nearly 480 miles each of oil and natural gas pipelines down the length of Sakhalin Island to the ice-free port of Prigorodnoye. The Sakhalin-2 energy project currently produces oil in the six months of the year when the bitterly cold seas off the island's eastern shores are free of ice. Sakhalin Energy's plan is expensive, but will allow year-round oil and natural gas exports.

The rival Sakhalin-1 group favors a shorter, 150-mile underwater pipeline. Sakhalin-1 partners propose to export their oil across the Tatar Straits to DeKastri, on the Russian mainland, where an existing tanker terminal could be expanded to handle exports to Asia. It will be much cheaper to build, but off-takers will have to contend with ice for several months a year. Capacity of both the terminal and pipeline is planned at 240,000-300,00 b/d. Sakhalin-1 says its export route will be cheaper than that of Sakhalin-2, and although Sakhalin-1 is attempting to speed up its timetable to start production in 2003 instead of 2005 as originally scheduled, Sakhalin-1 acknowledges that exports will not begin before 2005.

CPC Pipeline
In March 2001, the Caspian Pipeline Consortium's (CPC) Tengiz-Novorossiisk pipeline was commissioned. The CPC pipeline, which is run by an international consortium rather than Transneft, has an initial capacity of 564,000 bbl/d, with throughput eventually increasing to 1.34-million bbl/d in 2015. Oil from the Tengiz field in Kazakhstan began to flow via the 990-mile pipeline to Russia's Black Sea port of Novorossiisk, but flows were suspended several times because the CPC did not have an agreement with Russia's State Customs Committee to transit Russian territory. After Russia and Kazakhstan negotiated an oil transportation agreement and an "oil quality bank", the first tankers were loaded at Novorossiisk in October 2001.

With a 24% stake, the Russian government is the largest shareholder in the Caspian Pipeline Consortium, but the lack of a pipeline linking the CPC pipeline with Russia's Transneft pipeline system currently prevents Russian oil from flowing through the CPC pipeline. As a result, the ChevronTexaco-led Tengizchevroil consortium looks set to be the only bidder for pipeline space in 2002. Future inclusion of Russian crude will require Transneft to link its system to the CPC pipeline, as well as additional regulations or changes to the existing oil transit agreement and quality bank.

Druzhba-Adria Pipeline Integration
In October 2000, Yukos announced plans to integrate the Druzhba southern pipeline with the Adria

pipeline, which runs from the Adriatic port of Omisalj in Croatia to Hungary. Yukos signed a $20-million agreement with Croatian oil transport company Jadranski Naftovod to modernize the Adria pipeline to help integrate the two pipelines. By reversing the flows of the 110-mile pipeline between Omisalj and Sisak, the integration of the Druzhba and Adria pipelines will allow direct exports of Russian oil to the coast of the Adriatic Sea.

According to Yukos, Russian Urals blend crude oil should be flowing the 1,987-mile route to the deepwater Omisalj port by the end of 2002. In December 2001, the Ukrainian parliament ratified an agreement to reduce its tariff for Russian oil crossing its territory en route to Omisalj, a step that Russian oil companies had seen as the last major obstacle for the integration project to move forward. Ukraine's agreement to cut its transit tariff brought it in line with Belarus, Slovakia, Hungary, and Croatia, the other countries through which the route passes.

With the line reversed to Omisalj, Russian oil exporters will have direct access to the Mediterranean Sea, allowing them to bypass the Black Sea and the increasingly crowded Bosporus Straits. The entire Druzhba-Adria pipeline route would handle 100,000 bbl/d in 2003, the first full year of operation. Transneft and Jadranski Naftovod have said that exports via the pipeline would rise to 200,000 bbl/d after five years, and to 300,000 bbl/d after 10 years.

Sukhodolnaya-Rodionovskaya Pipeline
In September 2001, Transneft completed a 162-mile pipeline from Sukhodolny to Rodionovsky in the southern Rostov region, allowing oil headed south for the Russian Black Sea port of Novorossiisk to avoid transiting Ukraine. The 320,000-bbl/d line removes the need for Russian oil exporters to use a 60-mile stretch of pipeline in Ukraine. The original, Soviet-era pipeline sidetracked west into Ukraine to serve the Lisichansk refinery, but after the collapse of the Soviet Union, Ukraine began charging Transneft high transit fees to use the pipeline. Transneft decided it was worth the $240-million cost to construct a bypass pipeline in order to avoid Ukraine's high transit fees.

NATURAL GAS PIPELINES

Russia has a comprehensive domestic natural gas distribution system run by the state natural gas monopoly Gazprom, as well as a series of natural gas pipelines linking Russia to the former Soviet republics. Russia's main natural gas export pipelines to Europe run from West Siberia, across the Volga-Urals and Timan-Pechora, and through Ukraine and Belarus to Europe. The Brotherhood, Progress, and Soyuz gas pipelines, with capacities of 1 trillion cubic feet (Tcf) each, transit Ukraine, while the 1.0-Tcf Yamal-Europe pipeline crosses Belarus, and the 0.8-Tcf Northern Lights gas pipeline transits both Belarus and Ukraine.

With world natural gas demand increasing, Russia is attempting to increase its capacity to export its natural gas. In addition, with so many natural gas pipelines crossing Ukraine, Russia is seeking to build new pipelines to diversify its natural gas export routes. In order to reach lucrative markets in Western Europe and Asia, Russia is proceeding with the construction of a number of international natural gas pipeline projects, including the Blue Stream pipeline to Turkey, and possible pipelines from Russia's

Sakhalin Island to Asian markets.

"Blue Stream" Pipeline
In 1997, Russia and Turkey signed an intergovernmental agreement for the sale of 565 billion cubic feet (Bcf) per year of natural gas, beginning in 2001. To implement this agreement, the "Blue Stream Pipeline Company" was formed, and the countries agreed to build a pipeline directly from Russia to Turkey, via the Black Sea.

Construction on the 565-Bcf-per-year-capacity Blue Stream pipeline officially began in February 2000. The pipeline includes a 222-mile section in Russia, from Izobilnoye to Dzhugba on the Black Sea Coast, a 235-mile section on the bottom of the Black Sea that will connect Dzhugba to Samsun on the Turkish coast, and a further 300-mile link from Samsum to Turkey's capital at Ankara. The estimated cost of the pipeline, which is Russia's largest investment project, is between $3 billion and $3.3 billion. The seabed stretch of the pipeline, which will be laid at depths deeper than any other pipeline in the world, is estimated to cost $2 billion alone. ENI (Italy) and Gazprom each have a 50% stake in the Blue Stream project.

In the spring of 2001, investigations into allegations of corruption in Turkey in the tendering for the Blue Stream pipeline set the project back several months. Turkey's Energy Minister, Cumhur Ersumer, was forced to resign after being named in a court indictment of 15 ministry officials charged with corruption. Aside from setting back the timetable for completion of the project, the Blue Stream pipeline itself was unaffected, and in August 2001, the Saipem 7000, an Italian technological innovation that is the only ship in the world capable of laying pipelines at such depths, began laying the pipeline at the bottom of the Black Sea at a depth of nearly 7,000 feet.

In February 2002, the Saipem 7000 completed laying the first of two branches of the subsea section of the pipeline, with work on the second branch to be completed in May 2002. Construction of the Turkish onshore section of the pipeline is already complete, while the 222-mile Russian section of the pipeline, which includes compressor stations and underground storage facilities, is scheduled to be finished by September 2002.

Natural gas supplies through the Blue Stream pipeline are slated to being in the third quarter of 2002, with Russia scheduled to deliver 70.6 Bcf of natural gas to Turkey via the pipeline this year. From 2003 to 2009, Russia will increase deliveries via Blue Stream by 70.6 Bcf per year each year, with the pipeline reaching peak capacity of 565 Bcf per year in 2009. Over the course of the 25-year agreement, Russia will pipe 14.1 Tcf of natural gas to Turkey.

Ukraine Bypass and Yamal-Europe Pipelines
Gazprom currently supplies around 25% of European natural gas demand, and the company is eager to increase its penetration in the region. Approximately 90% of Russia's total natural gas exports to Europe are routed through Ukraine, which receives natural gas supplies as in-kind payment for allowing Russia's natural gas to transit its territory en route to European consumers (Ukraine purchases additional natural

gas from Russia to meet its domestic demand). The Yamal-Europe pipeline, which is routed through Belarus and Poland to Germany, is Russia's only natural gas export pipeline to Europe that is not routed through Ukraine.

Russia has questioned Ukraine's reliability as a transit country, noting Ukraine's $2-billion debt for natural gas supplies. Several times in the past few years, Russia has accused Ukraine of illegally taking more natural gas from than the amount for which it had contracted. With Russia's long-term energy supply agreement with the European Union, Russian officials have said that they need additional export routes to be able to meet Russia's increased supply obligations. As a result of the strained relations between Ukraine and Russia over natural gas transit, in October 2000 Gazprom officials proposed a new pipeline that would bypass Ukraine. However, Ukraine pledged to stop siphoning natural gas from the transit pipelines, and in October 2001, the two countries agreed on a 12-year debt restructuring deal for Ukraine's natural gas debts.

Gazprom has sent conflicting signals on its intentions with the second leg of the Yamal pipeline (stipulated in a 1993 Russia-Poland intergovernmental agreement) and the related question of a possible bypass route around Ukraine. In February 2002, Gazprom board member Boris Fyodorov told investors that the company's board of directors had decided to increase the capacity of the Yamal-Europe pipeline and drop the project to build the natural gas pipeline through Poland, bypassing Ukraine. Gazprom officials, however, denied reports that the company has scrapped plans for a north-south pipeline from Belarus to Slovakia via Poland, avoiding Ukraine.

Although there has been confusion as to what Gazprom's position is, what is clear is that the company is still interested in boosting Russia's natural gas export capacity to Europe by diversifying its export routes. Currently, the Yamal-Europe pipeline annually carries about 600 Bcf of Russian natural gas, which is sold to the Russian-German trading company Weih, and the pipeline is expected to handle about 1.17 Tcf of natural gas per year by 2003 after new compressor stations have been built in Poland. Gazprom's plans for a second stretch of the Yamal-Europe pipeline through Poland would increase capacity to 2.1 Tcf of natural gas per year, but Russia and Poland have differed on the route for the second leg, and Russia's shorter route would still cost an estimated $2 billion to construct. As a result, Yamal-Europe II appears to be on hold.

China Natural Gas Pipelines

Russia also is looking to eastern markets to export its natural gas to Asian countries. On September 29, 2000, Russia announced that it would expedite the development of eastern Siberia natural gas fields, as well as conduct a feasibility study for laying a natural gas pipeline to China in a bid to supply natural gas to China. Several international projects are seeking to deliver Russian natural gas to China, although China has narrowed it down to two major options: a BP (U.K.)-led consortium that is developing the Kovykta natural gas field, and the the Sakha consortium developing the Chayandinovskoye field. Analysts believe that only one pipeline will be needed.

The Chayandinovskoye option would cost approximately $6 billion-$10 billion and would entail a 1,700-

mile pipeline link from the Chayandinskoye field to Xinjiang region northern China. In March 2001, Russia's Sakhaneftegaz and China's National Oil & Gas Development Corp. signed a preliminary agreement to develop the Chayandinovskoye field, which is estimated to contain 43 Tcf of natural gas, and build a dedicated pipeline with capacity of between 423 Bcf and 706 Bcf per year. Gazprom may act as the operator for the pipeline.

The second option for China to receive Russian natural gas is via a pipeline linking Russia's Kovykta field in Irkutsk with northeastern China. The Kovykta field, which is being developed by Russia Petroleum, a BP-led consortium, has estimated natural gas reserves of 49 Tcf. The pipeline would terminate in South Korea via a sub-sea pipeline across the East China Sea. The most direct route for the proposed Irkutsk pipeline--which Russia Petroleum strongly prefers--would be to lay the pipeline through Mongolia into northern China and then down to South Korea.

However, China is urging that the pipeline bypass Mongolia and instead go around the eastern edge of that country and follow a route on to Manzhouli in northeastern China, then cross into North Korea before terminating in South Korea. China feels that a route across Mongolia would be geopolitically risky and argues that Mongolian natural gas demand does not justify having the pipeline cross its territory.

If China insists that the pipeline not traverse Mongolia, an extra 700 miles will be added to the 2,000-mile pipeline route. In addition to the political issues related to the pipeline crossing North Korea, the added cost (from the extra length) of the pipeline may make the extension to South Korea unfeasible. Thus far, Russia Petroleum has failed to agree on the price China will pay for the natural gas.

North TransGas Pipeline
In late April 2001, Gazprom signed an agreement with Finnish and German customers for a feasibility study on a pipeline that would carry Russian natural gas across the Baltic Sea to serve Scandinavia and Germany. The North TransGas pipeline, if it is built, will be well located to export natural gas production from the far north of European Russia and the Barents Sea, and also will allow Gazprom to avoid negotiating fees for transit countries. Gazprom's partners in the North TransGas pipeline project are Finland's Fortum and Germany's Wintershall and Ruhrgas. However, until Gazprom is restructured and attracts more foreign investment, it appears that only one of the proposed northern natural gas pipelines--Yamal-Europe II or the North TransGas pipeline--is possible due to Gazprom's financial woes.

Sakhalin-1 Natural Gas Pipeline to Japan
The Sakhalin-1 consortium, made up of ExxonMobil (U.S.), Rosneft, ONGC Videsh (India), and a consortium of Japanese firms, is developing the Odoptu, Chayvo and Arkutun-Dagi oil and natural gas fields on Sakhalin Island off Russia's Pacific Coast. The consortium is proposing to deliver natural gas from Sakhalin to Japan via a 120-mile pipeline linking its fields with Sapporo, on Japan's northernmost island of Hokkaido. A feasibility study for the pipeline, which could be extended to Tokyo, is scheduled to be completed in April 2002.

ExxonMobil, the project's operator, previously has stated that it believes the pipeline will be economically viable. ExxonMobil has already given the green light to increase investment at the fields, and the company has announced that Sakhalin-1 is planning to produce 335 Bcf of natural gas per year in 2003. Sakhalin-1 hopes to start piping natural gas to Japan in 2008, with exports reaching 360 Bcf per year.

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Energy Information Administration

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Ukraine

Ukraine is important to world energy markets because it is a critical transit center for exports of Russian oil and natural gas to Europe, as well as a major energy producer and consumer in its own right.

Information contained in this report is the best available as of August 2002 and is subject to change.

GENERAL BACKGROUND

Following eight consecutive years of recession, Ukraine experienced its second straight year of economic growth in 2001. Fueled by increases in industrial production and a strong harvest, Ukraine's real gross domestic product rose an impressive 8.9% in 2001, improving on the 5.8% GDP expansion in 2000. Although growth has slowed somewhat in 2002, analysts are still projecting Ukraine's economy to increase by 5.6% overall this year.

Although Ukraine has witnessed a substantial cooling of inflation (6% in 2001, down from 25.8% in 2000) and there has been a marked drop in unemployment, in many ways Ukraine remains mired in the transition from a centrally-planned economic system to a market economy. While the country's recent economic gains appear to signal that Ukraine has turned the corner, the government remains burdened by a 12 billion foreign debt that is continuing to increase.

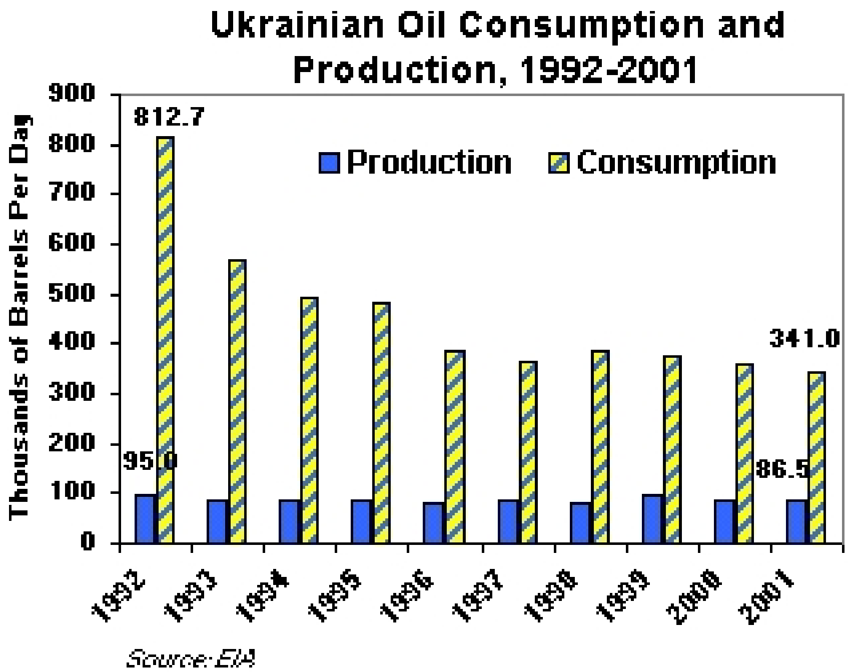
In addition, the confusing web of tax requirements and excessive state interference in the private sector has contributed to a poor investment climate, and the pace of reforms has slowed considerably since Victor Yushchenko was ousted as Prime Minister in April 2001. Yushchenko, a former chairman of the National Bank of Ukraine, pushed through a number of economic reforms during his time in office before he lost a parliamentary vote of no-confidence in Ukraine's parliament, the Verkhovna Rada.

Under the leadership of Anatoly Kinakh, who was installed as Prime Minister by Ukrainian President Leonid Kuchma in May 2001, the Ukrainian government pushed through tax and land reforms in the fall of 2001, but the reform process slowed in the run-up to parliamentary elections on March 31, 2001. Energy sector reforms are still needed, although the Ukrainian government has taken a number of halting steps forward in 2002. Still, Ukraine's energy sector is riddled with debt, and its energy sector suffers from outdated equipment and a lack of funds for modernization. In addition, Ukraine's lack of domestic natural resources means that the country is heavily dependent on Russia for energy supplies, making good relations with its eastern neighbor a necessity.

OIL

Ukraine has 395 million barrels of proven oil reserves, the majority of which are located in the Dnieper-Donetsk basin in the eastern part of the country. Although the pace of exploration has picked up, particularly in Ukraine's sector of the Sea of Azov, Ukraine's oil production steadily declined in the years following the country's independence, from 95,000 bbl/d in 1992 to 82,000 bbl/d in 1998. With the rise in world oil prices in 1999, Ukraine's oil output shot up to 98,500 bbl/d before tailing off again to 88,300 bbl/d in 2000. In 2001, Ukraine produced 86,500 bbl/d of oil, and Naftohaz Ukrainy, the country's state-owned umbrella oil and gas company, reported that oil production is down 0.7% through the first quarter of 2002.

Ukraine's oil production volumes satisfy only about 25% of the country's domestic needs, making Ukraine highly dependent on foreign oil supplies. Although Ukraine's oil consumption has dried up dramatically since it began the transition to a market economy--decreasing 58%, from 813,000 bbl/d in 1992 to 341,000 bbl/d in 2001--the country's consumption still far outstrips its production capacity. Ukraine imports the majority of its oil from Russia, with lesser amounts coming from Kazakhstan.



Oil Transit
With a highly developed oil pipeline system, Ukraine plays an important role as a transit country for Russian oil exports to Europe. The southern branch of the 1.2-million-bbl/d Druzhba pipeline from Russia transits Ukraine en route to Slovakia, Hungary, and on to western Europe.

In addition, due to its geographic location and its oil pipeline system, Ukraine has an excellent opportunity to play a major role in bringing increased oil exports from Azerbaijan and Kazakhstan to European oil markets. Rather than seeking to import Caspian Sea region oil for domestic consumption, Ukraine is hoping to reap tariffs for Caspian oil transiting its territory as it heads westwards.

The chief components of Ukraine's strategy are the newly constructed Pivdenny oil terminal and the 560,000-bbl/d Odesa-Brody pipeline, which cost a combined $750 million to build. Ukraine is hoping to entice Caspian oil exporters shipping oil via the Black Sea to bypass the crowded Bosporus Straits, already a major chokepoint for tankers, and instead send their oil to European markets via Ukraine. However, Ukraine has not yet found any oil companies to fill the pipeline, and the country's attempts to make itself more attractive to investors--by stepping up oil sector privatization efforts or by proposing that an international consortium to manage the pipeline--have seen only limited results thus far.

Refining/Downstream
Ukraine has six refineries, with a combined crude oil refining capacity of just over 1.1 million bbl/d. However, with domestic demand at just over 30% of the country's refining capacity, Ukraine's refineries are operating significantly below capacity. Until recently, Ukraine's refineries did not even receive enough crude oil supplies to supply the country's petroleum product demand.

Ukraine has begun to achieve better results in securing sufficient crude oil supplies for its refineries by offering oil exporters in Russia and Kazakhstan a stake in the country's refineries. Ukraine's recent success in privatizing its refineries has allowed the country to secure additional oil supplies to meet domestic demand, as well as to attract funds for necessary renovation work and to boost utilization rates at its refineries.

Although still operating far below its 320,000-bbl/d potential, throughput has increased at the Lisichansk (LiNOS) refinery since Russian oil major Tyumen Oil (TNK) purchased 67% of the refinery in July

2000. Likewise, with Lukoil's purchase of a controlling share in the Odesa refinery, the Russian oil company agreed to pay $39.6 million of the refinery's debts and promised to supply 48,000 bbl/d of crude to the refinery annually until 2004. Ukraine boosted its imports of petroleum products by 8% in the first quarter of 2002 while crude oil supplies to refineries declined, owing to increased exports of refined products from Russia.

NATURAL GAS

Ukraine has natural gas reserves of 39.6 trillion cubic feet (Tcf). The country's natural gas production, which stood at 636 billion cubic feet (Bcf) in 2000, has remained relatively flat since 1995. In the first five months of 2002, Ukraine produced 272.8 Bcf of natural gas, a 1% year-on-year increase. Of this total, Naftohaz Ukrainy, the country's state-owned natural gas company, extracted 262.2 Bcf, accounting for 96% of the country's total natural gas output.

According to Chornomornaftohaz, a division of Naftohaz Ukrainy, three new natural gas deposits have been found on the southern Sea of Azov shelf in the last few years. As many as 13 natural gas and condensate and dry gas deposits with a combined 2.6 Tcf of possible reserves are on the shelf, but Ukraine's biggest natural gas deposits are already over 90% exhausted, and many of the country's recently developed natural gas deposits have been quite small. In June 2002, Chornomornaftohaz, which is developing four natural gas fields in the Black Sea, made a proposal to foreign investors to set up a $20 million joint venture to develop the Odesa natural gas field, which holds proven reserves of 389 Bcf.

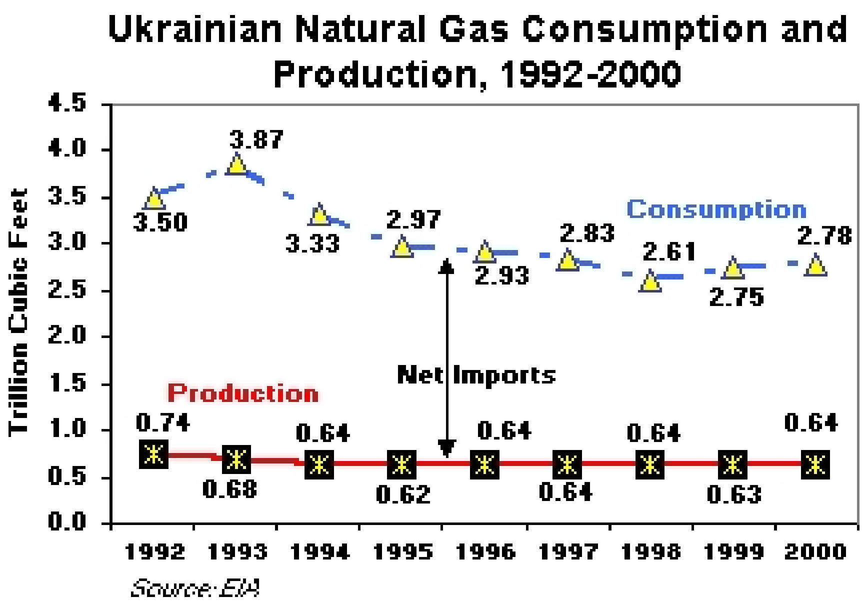
Still, Ukraine's consumption of natural gas far exceeds the country's natural gas production. In 2000, Ukraine consumed 2.78 Tcf of natural gas, leaving the country dependent on imports for nearly 80% of its consumption needs. Traditionally, Russia has been Ukraine's major source of natural gas supplies, with Ukraine receiving up to 1.1 Tcf per year of Russian natural gas as payment for transiting Russian natural gas to European markets.

Due to Ukraine's deficiency of indigenous natural gas, Ukraine has been forced to buy additional natural gas from Russia beyond what it receives as compensation for transit. In 2002, for the first time, Ukraine received natural gas from Russia as payment for transit services, but did not buy any additional supplies. Instead, Ukraine imported natural gas from Turkmenistan in order to supplement its own domestic production.

Ukraine-Russia Natural Gas Accords

Ukraine has run up a substantial debt to Russia for natural gas already supplied. In addition, Russia accused Ukraine of illegally siphoning natural gas destined for European consumers between 1998 and 2000, leading to heightened tensions between the two countries and prompting Russia to pursue plans to build a "Ukraine bypass" natural gas pipeline to Europe. Nearly 90% of Russia's natural gas exports travel to Europe via Ukraine.

With Ukraine's continued illegal siphoning of Russian natural gas in early 2000, Russia clamped down, demanding Ukraine pay its nearly $2 billion natural gas debt and halt unauthorized Russian natural gas consumption. In the fall of 2000, Russia offered to swap Ukraine's natural gas debt for equity in Ukraine's transit pipelines. However, Ukraine balked at the idea, and in May 2001 Ukraine reduced its dependence on Russian natural gas by contracting with Turkmenistan to receive 8.83 Tcf of natural gas between 2002 and 2006. The Turkmenistan deal will provide Ukraine with nearly 60% of its projected natural gas needs during that time period.



In December 2001, the sides broke the deadlock by coming to an initial agreement on Ukraine's debt for Russian natural gas supplies. Ukrainian and Russian negotiators agreed that Ukraine owes Russia $1.4 billion and that the sum will be paid over the next ten years, with no debt payments other than interest to be made in the first three years. In February 2002, the board of directors of Gazprom, the Russian natural gas monopoly, failed to address the issue of the proposed Ukrainian bypass pipeline, a move that analysts said signaled that the company did not have the financial wherewithal to undertake the project.

In June 2002, relations between Ukraine and Russia on the issue of natural gas transit warmed considerably as the sides agreed on a long-term transit agreement, as well as a preliminary deal to create an international consortium to manage and modernize Ukraine's natural gas transit pipeline system. The countries also signed a protocol to an earlier transit agreement, specifying that Ukraine would receive 918 Bcf of natural gas in 2003 as payment for transiting up to 4 Tcf of Russian natural gas to Europe, while Russia agreed to transit 1.06 Tcf of Turkmen natural gas for Ukrainian consumption. In addition, Ukraine agreed to allow Gazprom to operate Ukraine's underground natural gas storage facilities until 2013.

Future Natural Gas Imports

According to a study by the Ukrainian National Academy of Science, Ukraine's natural gas consumption could double by 2030, while the country's natural gas production may only increase 33% over that time period. As a result, Naftohaz Ukrainy is considering alternative sources of natural gas, including Iran and Norway. However, Mikhail Derkach, deputy chief executive officer of Naftohaz Ukrainy, has stated that it is not beneficial to buy Norwegian natural gas through Poland because of the high cost.

With construction of a natural gas pipeline from Iran to Armenia under development, Ukraine believes that an Iran-Armenia-Georgia-Crimea pipeline is possible, linking the pipeline from Georgia across the Black Sea to Ukraine's Crimean port of Feodosia. Iran is looking to increase its natural gas imports to Europe, and Ukraine is interested in maintaining its position as the major transit point for natural gas to Europe. However, the distance and substantial projected cost of such a pipeline has inhibited the implementation of this plan.

Thus, according to Derkach, Ukraine's most realistic plan is to increase natural gas imports from Turkmenistan. Ukraine currently imports natural gas from Turkmenistan for $42 per 1,000 cubic meters (35,300 cubic feet), which Ukraine pays for 50% in cash and 50% through participation in construction and industrial projects in Turkmenistan. The May 2001 deal is contingent on Ukraine remaining current in its natural gas payments to Turkmenistan, but Ukraine still owes Turkmenistan approximately $280 million for natural gas supplied between 1993 and 1994. The two countries have agreed on a schedule of current debt payments of $46 million for natural gas supplies in 2002.

COAL

Ukraine has 37.6 billion short tons in proven coal reserves, accounting for over 60% of the former Soviet Union's total coal reserves. Most of Ukraine's coal is mined in the Donetsk/Donbas basin in the eastern region of the country. In the mid-1990s, Ukraine's coal production dropped 43%, from 147.3 million short tons (Mmst) to 83.5 Mmst, before inching back up to 90.3 Mmst in 2000. Through the first five months of 2002, Ukraine produced 31.1 Mmst of coal, 0.4% less than in the same period of 2001.

The decline in Ukraine's coal production during the 1990s was caused in large part by the collapse of domestic demand--which, at 97.2 Mmst in 2000, still exceeds domestic supply--and the closing of heavy industry as Ukraine's economy contracted. Since Ukraine became independent in 1991, the country's coal sector has fallen into disarray: the industry, which counts 193 mines and employs around 450,000 people, suffers from labor strikes, hazardous working conditions, inefficiency and low productivity, corruption, consumer nonpayments, unpaid wages and huge debts, and outmoded equipment.

Ukraine's coal mining sector, which remains heavily subsidized by the Ukrainian government, has the world's highest death rate, mostly the result of obsolete equipment and low safety standards. On July 7, 2002, a fire at the Ukraina mine in eastern Ukraine killed 35 miners, the latest in a series of deadly accidents. Through the end of July 2002, over 150 miners had died in mining accidents in Ukraine this year, following nearly 300 deaths in 2001.

Meanwhile, the industry's debt level has risen to more than $2 billion--over 50% greater than the value of annual production and twice as much as its accounts receivable. Attempts to reform the sector began in 1996 but had little effect as the then-Ministry for Coal concentrated on barter deals, investments and subsidies while lobbying for a ban on coal imports. Although some reforms have begun to take root and wage arrears are beginning to be paid down, coal sector privatization has stalled, and a $300 million World Bank structural adjustment loan that was designed to close down more than 80 loss-making pits between 1997 and 2000 failed to close even half of those mines.

In September 2001, the Ukraine cabinet approved an $8.8 billion program to revive the country's coal sector over the next ten years. The program recognizes that the industry must switch to cash payments, improve mines, budgeting and asset management, seek investment sources, and reduce the mines' high level of debts before proceeding with further privatization. The program also aims to improve mine safety and work practices, as well as providing for a reduction in the number of coal mines to 157 in 2010. About two-thirds of Ukraine's 193 mines are unprofitable.

The World Bank has criticized Ukraine's coal mining strategy, saying that it contains no major mechanisms that would reduce barter and that the plan closes too few mines too slowly. However, in February 2002, Viktor Yanukovich, the head of administration of the Donetsk coal mining region, described the World Bank's suggested plan to close 50 to 60 mines in the next two or three years as "unacceptable" because it would result in a considerable decrease of jobs in the region. Although Ukraine's mines are expensive to operate, the Ukrainian government has been reluctant to reduce the number of mines due to the social costs of closing so many pits in an area with few other jobs.

Instead, the Ukrainian government plans to hike coal prices for the country's power generators by 10% before the end of 2002 and reduce state subsidies for the sector. Coal prices are to be increased to approximately $28.20 per metric ton, up from the current $25.60 per metric ton. The price hike should help the coal sector raise an additional $165 million after the government cut state subsidies. The Ukrainian government originally planned to spend $324 million to subsidize the coal sector in 2002, but due to a financial crunch can provide only $159 million, according to analysts.

ELECTRICITY

Ukraine's power sector, with 53.9 gigawatts (GW) of installed capacity, is plagued by debt and inefficiency. Thermal power plants (oil natural gas, coal) account for nearly 50% of the power produced in Ukraine, with nuclear power generating another 40%, and hydroelectric accounting for approximately 10%.

With four major thermal-fired power plants with 17 power generators, as well as four nuclear power plants with 13 reactors, Ukraine has enough generating capacity to produce twice its electricity needs. However, due to the inefficient and antiquated transmission and distribution network that the country inherited from the Soviet Union, a significant amount of power generated in Ukraine is wasted via line losses. According to Ukraine's Fuel and Energy Ministry, losses in electricity lines accounted for 21% of the total amount of electricity generated in 2000. Overall, Ukraine produced 163.6 billion kilowatt-hours (Bkwh) of electricity in 2000 against consumption of 151.7 Bkwh.

In February 2001, Russia and Ukraine struck a deal to reconnect their energy grids, providing Ukraine with a more stable electric frequency and allowing Russia to export its electricity to other countries--including Moldova, Romania, Bulgaria, and the Balkans--via Ukraine. Although the grids were supposed to be reconnected on March 1, 2001, the grids were not actually linked until August 2001.

Until recently, Ukraine's power sector also was beset by shortages of fuel for power generators. Since natural gas accounts for over 40% of the primary fuel consumption of Ukrainian thermal power plants, the country's reliance on Russian natural gas affects Ukraine's electricity sector as well. In mid-January 2001, Itera cut off natural gas supplies to four Ukrainian thermal electric power generators in order to force payment of debts for natural gas already supplied. With the recent agreements between Russia and

Ukraine on natural gas supplies and transit, as well as a plan for Ukraine to pay its natural gas debts, the problem of natural gas cutoffs to power generators appears be resolved.

Non-payment by consumers is another obstacle hindering the further development of Ukraine's power sector. Although Ukraine's 27 regional energy distributors--called *oblenerhos*--legally are allowed to cut off non-paying customers to reduce losses and enforce payment discipline, in practice this often cannot be done without government permission. Nevertheless, owing to reforms in the sector and increased economic growth leading to a rise in per capita income, the percentage of power bills paid in cash has risen from below 10% in 1999 to approximately 86% as of July 2002.

With the cycle of debt in the state-run power generating and distribution sectors, Ukraine has been trying to privatize its regional energy distribution companies in order to relieve the government of the heavy debt burden. The country partially privatized the first seven *oblenerhos* in 1998, then sold stakes in another six of the regional distribution companies in April 2001.

However, in May 2001, President Leonid Kuchma ordered a temporary halt to the privatization of the remaining *oblenerhos*, pending a presidential review of the recent privatizations and additional reforms to the sector. In December 2001, Kuchma lifted the ban on the sale of the *oblenerhos*, and Ukraine is hoping to sell controlling stakes in 5 *oblenerhos* before the end of 2002, with the remainder to be sold in 2003.

Nuclear
Ukraine currently has four operating nuclear power plants. These power plants have a total capacity of 11.8 gigawatts, which accounts for approximately 22% of the country's total power-generating capacity. Ukraine's nuclear power plants produce 40% of the country's power output, despite frequent malfunctions and lengthy repairs and maintenance.

On December 15, 2000, Ukraine permanently shut down the 925-MW, Unit 3 at the Chornobyl power plant, disabling the last remaining working reactor at the ill-fated power plant. To replace the power generated by Chornobyl, which Ukrainian officials say produced approximately 5% of the country's total, Ukraine has resumed construction of two 1-GW reactors at the Khmelnitsky and Rivne power plants.

Construction of Khmelnitsky-2 and Rivne-4 was begun under the Soviet Union, and both were more than 80% finished when Ukraine received its independence and ran out of money to complete them. Ukraine is hoping to finish construction of both reactors with the help of financing from the European Bank for Reconstruction and Development (EBRD), but an EBRD loan for the project was put on hold in December 2001. Russia then offered Ukraine a $500 million loan to allow the country to finish construction of the two reactors, but most experts believe the reactors cannot be completed without additional financing. Ukraine is still negotiating with the EBRD to secure additional financing for the estimated $1.4 billion project.

ENVIRONMENT

The 1986 Chornobyl nuclear meltdown exposed the Soviet Union's negligent environmental record and triggered alarm across the globe. The world's worst nuclear accident created disastrous consequences for the environment, both in Ukraine and in neighboring countries. As a result, Soviet policies that encouraged industrial development at the expense of the environment came under harsh international criticism, and Chornobyl became a rallying cry for environmentalists around the world.

While Chornobyl remains the lasting symbol of environmental degradation in Ukraine, today air pollution in the major cities is a major problem. Yet, despite increased vehicle traffic, energy use is significantly lower now than in the mid-1990s. Although policies encouraging energy conservation and energy efficiency can take some of the credit, Ukraine's economic woes account for much of the reduction: as the economy contracted through the 1990s, industrial production and consumer demand dropped as well, resulting in lower carbon emissions. Ukraine's recent economic growth has led to increases in both carbon emissions and energy consumption.

In terms of energy consumption per dollar, Ukraine suffers from one of the highest levels of energy intensity in the world. The country's heavy dependence on coal makes it correspondingly high in carbon intensity, and the continued reliance on nuclear power--as well as a lack of financial resources or economic incentives--has stifled the country's use of renewable energies. In order to protect its environment better in the coming years, Ukraine will need to shift away from fossil fuels and break the link of economic output from environmental pollution.

COUNTRY OVERVIEW

President: Leonid Kuchma (since July 19, 1994)
Prime Minister: Anatoliy Kinakh (since May 29, 2001)
Independence: December 1, 1991 (from Soviet Union); National holiday: Independence Day, August 24, 1991
Population (7/01E): 48.7 million
Location: Eastern Europe, bordering the Black Sea between Poland and Russia
Size: 233,090 square miles, slightly smaller than Texas
Major Cities: Kiev (capital), Kharkiv, Donetsk, Dnipropetrovsk, Odesa, L'viv
Languages: Ukrainian (official), Russian, Romanian, Polish, Hungarian
Ethnic Groups: Ukrainian 73%, Russian 22%, Jewish 1%, other 4%
Religions: Ukrainian Orthodox - Moscow Patriarchate, Ukrainian Orthodox - Kiev Patriarchate, Ukrainian Autocephalous Orthodox, Ukrainian Catholic (Uniate), Protestant, Jewish

ECONOMIC OVERVIEW

Minister of Economy: Oleksandr Shlapak
Minister of Finance: Ihor Yushko
Currency: Hryvnia
Market Exchange Rate (8/5/02): US $1=5.22 hryvnia
Nominal Gross Domestic Product (GDP) (2001E): $37.2 billion; **(2002E):** $42.3 billion
Real GDP Growth Rate (2001E): 8.9%; **(2002E):** 5.6%

Inflation Rate (Change in Consumer Prices, Dec. 2000-Dec. 2001E): 6.1%; **(2002E):** 9.2%
Official Unemployment Rate (2001E): 3.8%; **(2002E):** 4.5%
Current Account Balance (2001E): $1.27 billion; **(2002E):** $1.12 billion
Major Trading Partners: Russia, EU, U.S., Turkey
Merchandise Exports (2001E): $17.0 billion; **(2002E):** $18.1 billion
Merchandise Imports (2001E): $16.8 billion; **(2002E):** $18.2 billion
Merchandise Trade Balance (2001E): $200 million; **(2002E): -**$123 million
Major Exports: ferrous and nonferrous metals, fuel and petroleum products, machinery and transport equipment, food products
Major Imports: energy, machinery and parts, transportation equipment, chemicals
External Debt (12/01E): $12.0 billion

ENERGY OVERVIEW

First Deputy Prime Minister (for Energy Issues): Oleh Dubyna
Minister of Fuel & Energy: Vitaliy Hayduk
President, Naftohaz Ukrainy (National Oil and Gas Company): Yuri Boiko
Proven Oil Reserves (1/1/02E): 395 million barrels
Oil Production (2001E): 86,500 barrels per day (bbl/d); **(2002E):** 80,000 bbl/d
Oil Consumption (2001E): 341,000 bbl/d
Net Oil Imports (2001E): 254,500 bbl/d
Crude Refining Capacity (1/1/02E): 1.15 million bbl/d
Natural Gas Reserves (1/1/02E): 39.6 trillion cubic feet (Tcf)
Natural Gas Production (2000E): 636 Bcf
Natural Gas Consumption (2000E): 2.78 Tcf
Net Natural Gas Imports (2000E): 2.14 Tcf
Coal Reserves (1/1/01E): 37.6 billion short tons
Coal Production (2000E): 90.3 million short tons (Mmst)
Coal Consumption (2000E): 97.2 Mmst
Electricity Generation Capacity (2000E): 53.9 gigawatts (GW)
Electricity Production (2000E): 163.6 billion kilowatt-hours (Bkwh)
Electricity Consumption (2000E): 151.7 Bkwh

ENVIRONMENTAL OVERVIEW

Minister of Ecology and Natural Resources: Serhiy Kurykin
Total Energy Consumption (2000E): 6.46 quadrillion Btu* (1.6% of world total energy consumption)
Energy-Related Carbon Emissions (2000E): 104.46 million metric tons of carbon (1.6% of world total carbon emissions)
Per Capita Energy Consumption (2000E): 130.3 million Btu (vs. U.S. value of 351.0 million Btu)
Per Capita Carbon Emissions (2000E): 2.1 metric tons of carbon (vs. U.S. value of 5.6 metric tons of carbon)
Energy Intensity (2000E): 193,312 Btu/$1995 (vs U.S. value of 10,918 Btu/$1995)**
Carbon Intensity (2000E): 3.13 metric tons of carbon/thousand $1995 (vs U.S. value of 0.17 metric tons/thousand $1995)**

Sectoral Share of Energy Consumption (1998E): Industrial (61.6%), Residential (15.6%), Transportation (14.1%), Commercial (8.6%)
Sectoral Share of Carbon Emissions (1998E): Industrial (64.6%), Residential (16.2%), Transportation (11.8%), Commercial (7.4%)
Fuel Share of Energy Consumption (2000E): Natural Gas (45.0%), Coal (29.7%), Nuclear (12.1%), Oil (11.5%)
Fuel Share of Carbon Emissions (2000E): Coal (46.3%), Natural Gas (40.1%), Oil (13.5%)
Renewable Energy Consumption (1998E): 175 trillion Btu* (36% increase from 1997)
Number of People per Motor Vehicle (1998): 10.6 (vs. U.S. value of 1.3)
Status in Climate Change Negotiations: Non-Annex I country under the United Nations Framework Convention on Climate Change (ratified May 13th, 1997). Signatory to the Kyoto Protocol (signed March 15th, 1999, not yet ratified)
Major Environmental Issues: Inadequate supplies of potable water; air and water pollution; deforestation; radiation contamination in the northeast from 1986 accident at Chornobyl Nuclear Power Plant.
Major International Environmental Agreements: A party to Conventions on Air Pollution, Air Pollution-Nitrogen Oxides, Air Pollution-Sulphur 85, Antarctic Treaty, Biodiversity, Endangered Species, Environmental Modification, Hazardous Wastes, Law of the Sea, Marine Dumping, Nuclear Test Ban, Ozone Layer Protection, Ship Pollution, Wetlands. *Has signed, but not ratified*: Air Pollution-Persistent Organic Pollutants, Air Pollution-Sulphur 94, Air Pollution-Volatile Organic Compounds, Antarctic-Environmental Protocol.

* The total energy consumption statistic includes petroleum, dry natural gas, coal, net hydro, nuclear, geothermal, solar and wind electric power. The renewable energy consumption statistic is based on International Energy Agency (IEA) data and includes hydropower, solar, wind, tide, geothermal, solid biomass and animal products, biomass gas and liquids, industrial and municipal wastes. Sectoral shares of energy consumption and carbon emissions are also based on IEA data.

**GDP based on EIA International Energy Annual 2000

ENERGY INDUSTRY

Organization: Naftohaz Ukrainy (state-owned oil and natural umbrella company with many subsidiaries, including UkrNafta (oil productionl), UkrTransNafta (oil transit), UkrTransHaz (natural gas transit), etc.); Enerhoatom (state-owned nuclear energy company).
Major Oil/Gas Fields: Dnieper-Donetsk Basin in eastern Ukraine, Precarpathian Basin in western Ukraine, Crimea, Arkhangelskoye (NW Crimea) Field, and the Sea of Azov
Major Oil Ports: Odesa, Sevastopol, Feodosia, Pivdenny
Oil Export Pipelines Crossing Ukraine: Friendship (Druzhba) (1.2 million bbl/d), Odesa-Brody (180,000 bbl/d, rising to 500,000 bbl/d), Eastern Products (30,000 bbl/d)
Major Oil Refineries (1/1/01 crude processing capacity): Kremenchuk (361,000 bbl/d), Lisichansk (320,000 bbl/d), Kherson (236,000 bbl/d), Odesa (78,000 bbl/d), Drogobich (78,000 bbl/d), Nadvornaja (74,000 bbl/d)
Foreign Oil and Gas Company Involvement: CanArgo Energy, Karpatsky Petroleum, Epic Energy,

EuroGas, Gazprom, JKX, LVR, Momentum Enterprises, Odesa Petroleum
Natural Gas Export Pipelines Crossing Ukraine (Capacity): Northern Lights (0.8 Tcf), Progress (1 Tcf), Shebelinka (0.7 Tcf), Soyuz (1 Tcf), Urengoy (1 Tcf), West Ukraine (0.15 Tcf)
Major Coal Fields: Donets/Donbass Basin, Lviv-Volhynian (West Ukraine) Basin, Dnieper Basin (lignite)
Nuclear Power Plants (Capacity): Zaporozhia (6,000 MW), South Ukraine (3,000 MW), Rivne (1,880 MW), Khmelnitsky (1,000 MW)

Sources for this report include: BBC Monitoring International Reports, CIA World Factbook, Current Digest of the Post-Soviet Press, DRI/WEFA Eurasian Economic Outlook, DRI/PlanEcon, The Economist, The Financial Times, FSU Energy, FSU Oil and Gas Monitor, Interfax News Agency, ITAR-TASS News Agency, Oil and Gas Journal, Petroleum Economist, Petroleum Report, Platt's International Coal Report, Platt's Oilgram News, Polish News Bulletin, PR Newswire, Project Finance, Radio Free Europe/Radio Liberty, Reuters, Ukraine Business Report, U.S. Department of Energy, U.S. Energy Information Administration, U.S. Department of State, Warsaw Business Journal, and World Markets Energy.

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Links to other sites:
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U.S. Department of Commerce, Country Commercial Guides
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May 2002

Central Asia: Tajikistan Energy Sector

TAJIKISTAN

Tajikistan, which suffered through a civil war between Islamic conservatives and the secular government after becoming independent in 1991, has the lowest per capita gross domestic product (GDP) in the former Soviet Union. Although a peace agreement between the United Tajik Opposition and the government of President Emomali Rakhmonov was signed in 1997, implementation has progressed slowly, and Russian-led peacekeeping troops remain posted throughout the country.

A modest economic recovery began after Tajikistan concluded a loan agreement with the International Monetary Fund (IMF) in 1997. The Tajik government brought inflation down to 13.5% in 2001 from 60.6% in 2000, and the country's real GDP grew by 9.5% in 2001. However, Tajikistan still faces major problems in integrating refugees and former combatants into the economy, and the country continues to depend on aid from Russia, Uzbekistan, and international humanitarian assistance for much of its basic subsistence needs. The future of Tajikistan's economy and the potential for attracting foreign investment depend upon stability and continued progress in the peace process.

Oil

Tajikistan has proven oil reserves of only 12 million barrels. The country's small oil industry is centered around the northern Leninobod Soghd Region. In 2001, Tajikneftegaz, which is responsible for all oil exploration, drilling, and production in Tajikistan, produced an average of just 350 barrels per day (bbl/d) of oil, continuing a downward trend that has seen the country's oil production drop off from 1,311 bbl/d in 1992. Tajikistan's 1992-1997 civil war, coupled with economic contraction and a lack of investment to maintain the oil sector's infrastructure, has resulted in a 73% decline in national oil production.

Tajikistan consumed approximately 29,000 bbl/d of petroleum products in 2001, of which nearly 100% is imported. In July 2001, Tajikistan opened its first refinery, the small 400-bbl/d-capacity Konibodom refinery, which produces gasoline, diesel, kerosene, and fuel oil. However, the country still must import much of its oil as refined petroleum products. Uzbekistan supplies more than 70% of Tajikistan's oil demand.

Natural Gas
With just 200 billion cubic feet (Bcf) in proven natural gas reserves, Tajikistan produces minimal amounts of natural gas domestically, leaving the country reliant on imports to meet domestic demand. In 2000, Tajikistan commissioned the Khoja Sartez natural gas field in the southern Khatlon Region, which, in combination with the increased utilization of the Qizil Tumshuq deposit in southern Khatlon Region's Kolkhozobod District, Tajikistan hopes will lead to increased domestic natural gas production. For 2000 as a whole, the country produced 1.4 Bcf of natural gas.

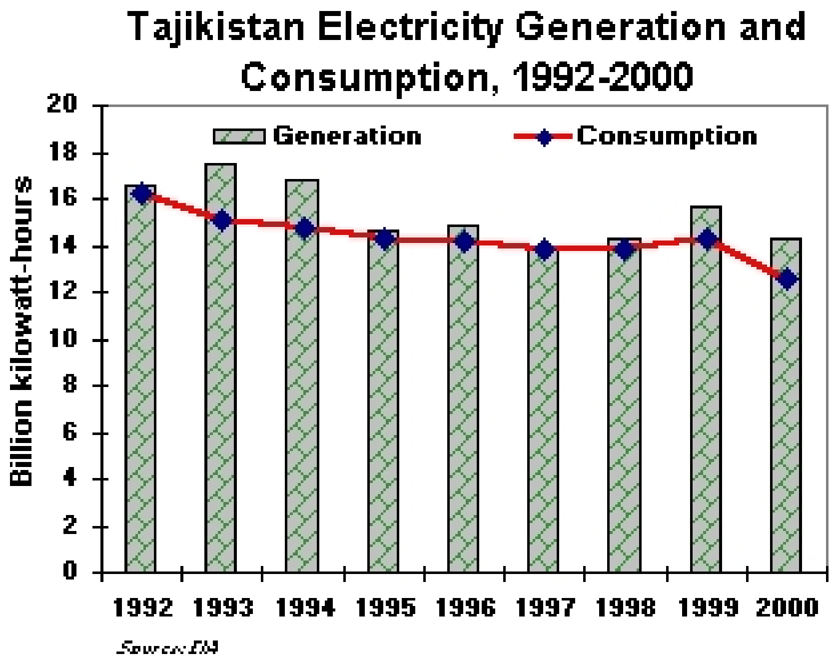
Tajikistan relies heavily on Turkmen and Uzbek natural gas to meet domestic demand, which stood at 44.1 Bcf in 2000. Due to distortions in the Tajik natural gas market, Tajikistan has continually run up debts to suppliers for natural gas already consumed. In addition, through April 2002, Tajikistan's population and industrial enterprises already had consumed about 80% of the annual volume of natural gas envisaged under an intergovernmental agreement between Uzbekistan and Tajikistan. Tajikgaz blames the high natural gas consumption and nonpayment by individual consumers (only 18% paid in 2001) on Soviet-era practices, when utilities were largely free. Tajikgaz has had to cut off nonpaying customers, as well as negotiate with suppliers for additional natural gas.

Coal
Tajikistan has 17 coal deposits, but the country's proven coal reserves are minimal. Since 1991, when Tajikistan produced approximately 430,000 short tons of coal, the country's coal production declined for seven consecutive years, to just over 11,000 short tons in 1998. Tajikistan's coal production rebounded to 22,000 short tons in 1999 and stayed at approximately that level in 2000. Preliminary 2001 figures reported by Tajikistan's Energy Ministry show that the country's coal production rose to 27,500 short tons, still below the country's consumption of 134,500 short tons of coal.

On April 16, 2001, President Rakhmonov signed a resolution on the establishment of Tojikangisht, a state coal enterprise uniting the country's two main coal producers, Leninobod Coal, a joint-stock company in the northern Soghd Region, and Fan-Yaghnob, a joint-stock company in the northern Soghd Region's Ayni District. In addition to these two companies and the mines of the same name, Tojikangisht also includes the Ziddi and Nazar-Ayloq coal fields in central Tajikistan. In 2001, Tojikanisht also set up several branches--Sayod, Hakimi, Miyonadu, Shurobod, and Saymiri--and embarked on opencast strip mining.

Electricity

Tajikistan had a total installed electricity-generating capacity of 4.4 gigawatts (GW) in 2000. Most of the country's electric power comes from seven large hydroelectric plants, which have a combined capacity of 4.05 GW. The Nureksk hydroelectric plant, which has nine units of 300 megawatts (MW) each, accounts for nearly 70% of this power. Other hydroelectric plants include Golovnaya, Baipazan, Namadgud, Lenin, Pamir-1, and Qayroqqum. Tajikistan also has several thermal power plants, with combined capacity of approximately 350 MW. In 2000, Tajikistan generated 14.2 billion kilowatt-hours (Bkwh) of electricity and consumed 12.5 Bkwh.



A significant portion of Tajikistan's power sector infrastructure is in poor condition as a result of the civil war and the lack of proper maintenance, which has contributed to increased energy losses of nearly 15% of generating capacity. Transformers are constantly breaking down due to overloads, and most power equipment has exhausted its service life; the Tajik government estimates that depreciation of energy equipment already has reached 75%. In addition, hydroelectric plants have been operating at well below capacity due to severe weather and low water levels.

Barq-i Tojik is the state company that controls electricity generation, transmission, and distribution in Tajikistan. The country has two power grids--a unified energy grid in the southern part of the country and a grid in the northern Soghd Region that is powered by the Qayroqqum hydroelectric station on the Syr Dar'ya River. The Qayroqqum plant can cover only slightly more than 30% of the northern region's energy needs, forcing the northern region to import power from Uzbekistan.

Tajikistan is hoping to modernize its power infrastructure by attracting foreign investment to the sector. The country is trying to increase its power-generating capacity and to reconstruct its energy grids. However, potential investors, which include international financial organizations and neighboring countries, are demanding that Tajikistan's power sector be privatized. Potential investors also want Tajikistan to change its rate policy: although the country's low electricity tariffs have increased bill collection to nearly 50% of energy deliveries, the policy has also resulted in huge losses for Barq-i Tojik, since the tariffs do not cover production costs. Tajik industrial enterprises and residential customers owe Barq-i Tojik more than $100 million.

Already, Barq-i Tojik has embarked on a $62-million project to refurbish Tajikistan's electricity sector. The main components of the project are to rehabilitate the Nureksk hydroelectric power station and the Jangal and Novaya substations, to restore the power grid in the southern region of Tajikistan, to install electricity meters on inter-system transmission lines, and to improve the company's service. Tajikistan also will raise electricity tariffs by 25% to 30% in 2002, with another 60% increase slated for 2003.

Completion of the Rogunsk and Sangtuda hydroelectric power stations are priorities for Tajikistan. The Rogunsk plant, which was begun during the Soviet period, has a design capacity of 3.6 GW, which will make it the 15th largest hydroelectric plant in the world. Construction of the 670-MW Sangtuda station, which also was begun before independence, has resumed with Russian and Iranian financing. Approximately $300 million still is needed to complete the Sangtuda power station. The Tajik government also is resuming a program to build 15 small hydroelectric plants, including Andarbak (250-MW capacity), Shkev (74 MW), Yemts (100 MW), Langar (60 MW), and Yamchun (150 MW).

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Energy Information Administration

October 2001

Regional Indicators: European Union (EU)

The European Union, with increasingly integrated economies and energy sectors, is the world's second-largest energy consumer (behind the United States). EU members include: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden, and the United Kingdom.

Note: Information contained in this report is the best available as of October 2001 and is subject to change.

BACKGROUND

The European Union (EU) was founded as the European Economic Community (EEC) by the Treaty of Rome in 1957 to promote economic and political integration in Europe. The founding of the EEC followed the creation of the European Coal and Steel Community, established after World War II as a means of promoting integration among former enemies. The EEC has expanded from its original six members (Belgium, France, the Federal Republic of Germany, Italy, Luxembourg, and the Netherlands) to include the United Kingdom, Ireland, and Denmark in 1973; Greece in 1981; Spain and Portugal in 1986; and Austria, Finland, and Sweden (former members of the European Free Trade Association) in 1995. The Treaty on European Union (known as the Maastricht Treaty) ushered in a new stage in European history when it entered into force on November 1, 1993. Maastricht renamed the community (now known as the EU), created European citizenship, strengthened the power of the European Parliament, laid out plans for Economic and Monetary Union (EMU), and committed members to negotiate for expansion of the EU to include Central and Eastern European countries. In 2000, EU members were estimated to account for 29% of world economic activity (see Table 1), a share that remained about constant during the 1990s. The United States has extensive trade relations with the EU. In 2000, 22% of U.S. exports ($152 billion) went to EU members, and 19% of U.S. imports ($195 billion) originated in EU countries.

As part of EMU, 11 EU member countries (Belgium, France, Germany, Italy, Spain, Portugal, Finland, Austria, the Netherlands, Ireland and Luxembourg) adopted a new common European currency, called the "euro," on January 1, 1999. The European Central Bank (ECB) is housed in Frankfurt, Germany. This means that a single monetary policy for the 12 particpating countries is elaborated at the ECB. Euro banknotes and coins are scheduled to begin circulating in all participating countries no later than January 1, 2002, and the euro is to replace completely all participating countries' national currencies by July 1, 2002. Most countries' banks have already been frontloaded with coins and banknotes, starting in September 2001.

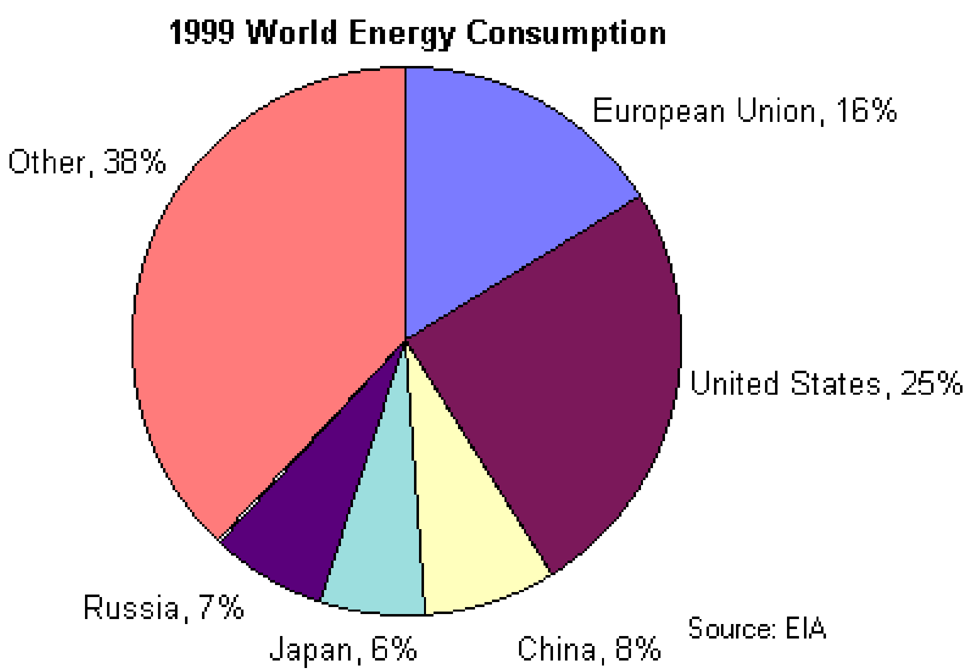
Greece was the only EU member country that applied but was denied entry to EMU at its introduction; in June 2000, Greece's application was accepted and Greece became a member of the euro-zone on January 1, 2001. The United Kingdom and Denmark opted out and Sweden purposely did not meet requirements. The euro-zone represents about 80% of the EU's GDP. The euro currently functions as a base currency for the currencies of all the countries participating in the euro; they are all fixed to the euro, and although the euro is not used as banknotes or coinage, the euro is the only currency that fluctuates in value with other currencies, including the U.S. dollar. The euro fell in value intially against the dollar, from being worth $1.18 in January 1999, to about $1.00 by the end of 1999, and $0.85 in October 2000, before rising again to $0.93 in January 2001. Since then, the euro has stabilized at between $0.93 and $0.85, being valued most recently at $0.91.

In 2001, the Treaty of Nice was signed by member governments. This treaty changes the way the institutions of the EU operate in order to make possible the admission of new member states in the future. Central and Eastern European EU applicants expected to join in the next phase of EU expansion include Poland, Hungary, the Czech Republic, Estonia, Slovenia and Cyprus. Some EU members are calling for a target date by which these applicants will be admitted officially. No date has been set, but membership is expected to extend to these six countries by about 2005. Slovakia, Bulgaria, Romania, Latvia, Lithuania, Turkey and Malta also have begun discussions of accession.

EU legislation has played a significant role in member countries' domestic energy policies. The EU Directive on Electricity was passed in January 1997 and required members to begin opening up their electricity markets to competition within two years (Greece, Belgium and Ireland were granted waivers). The EU Natural Gas Directive was passed in June 1998 (Greece, Belgium,and Ireland again were granted waivers), requiring the opening of EU members' gas markets. The Gas Directive has also affected Norway, as it is a member of the European Economic Area (EEA).

ENERGY CONSUMPTION

In 1999, EU countries consumed 62.7 quadrillion British thermal units (Btu) of energy (16% of the world's total) and generated 915 million metric tons of energy-related carbon emissions (15% of the world's total). Oil is the dominant fuel (see Table 2), accounting for 44% of 1999 total energy consumption in the region, followed by natural gas at 22%. In 1999, EU members consumed about 34% of the world's nuclear power, 18% of the world's oil, 16% of the world's natural gas, and over 10% of the world's coal. Over the past decade, natural gas has been the fastest growing fuel source in the EU, mainly at the expense of coal, whose share has declined sharply. This is in part due to environmental



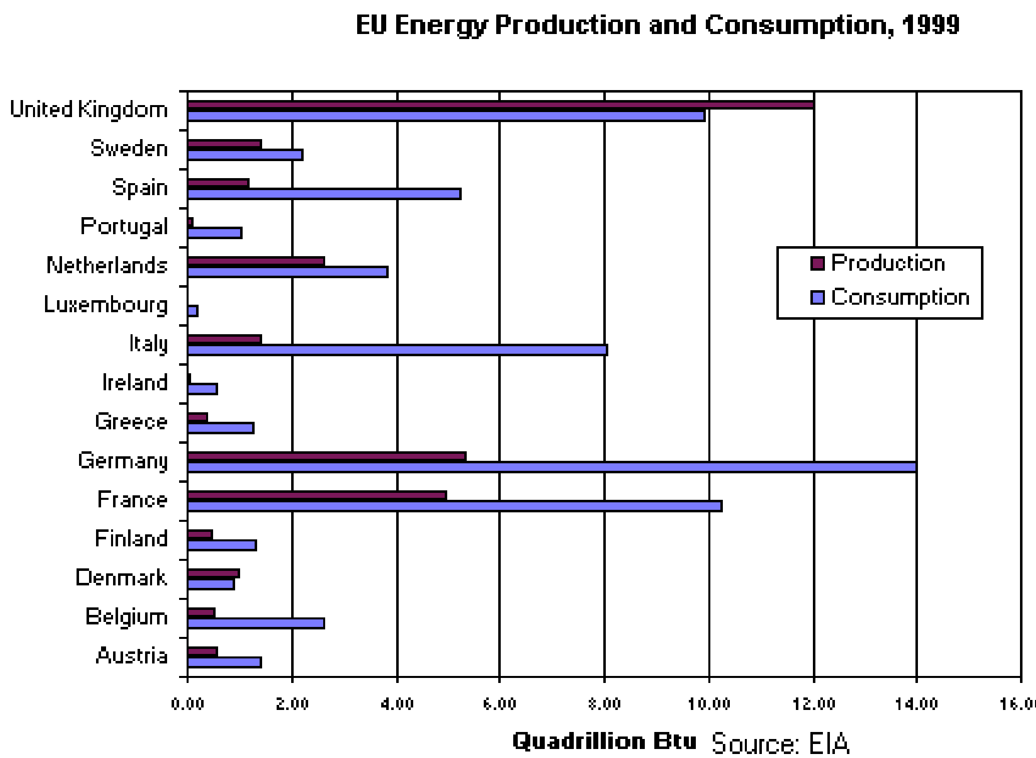
considerations, but also due to increased availability of natural gas supplies because of pipelines from Algeria, Norway, and Russia. Nuclear power generation has grown only slightly over the past decade. Nuclear power is gradually being phased out in Germany over the next twenty years, so its share of EU energy consumption is likely to drop. Hydroelectric power generation has remained about constant over the past decade. Other "renewables" (geothermal, biomass, solar, wind) doubled between 1992 and 1999, from a relatively small base level. Renewable energy and natural gas are expected to be the two fastest growing fuels in the EU over the next 20 years.

The combined economies of the EU are similar in size to the U.S. economy ($8.5 trillion gross domestic product for the EU in 2000 and $10 trillion for the United States), and the EU population of 379 million exceeds the U.S. population of 278 million. However, EU total energy consumption for 1999 of 63 quads is less than the U.S. consumption of 97 quads.

ENERGY RESOURCES AND SUPPLY

EU members possess only about 0.7% of the world's proven reserves of oil and 2.2% of the world's natural gas reserves (see Table 3). However, they have 7.4% of proven coal reserves, 16% of the world's capacity for refining crude oil into petroleum products, and 16% of the world's electric generating capacity. In 1999, they produced 5% of the world's crude oil, 9% of the world's natural gas, and 8% of the world's coal.

IMPORT DEPENDENCY



The EU region is a net importer of energy. In 1999, while the EU's 15 members consumed 16% of the world's energy, they produced only 8%. Import dependency varies by fuel and individual country, with an overall import dependency for the entire EU of around 50%. In 1999, the EU was a net importer of coal (8% of world production in terms of tonnage vs. 11% of consumption in terms of tonnage); natural gas (9% of world production vs. 16% of consumption); and oil (5% of world production vs. 18% of consumption). Germany, Italy, and France are the EU's largest net importers of energy; the United Kingdom is the only significant net exporter. EU oil is imported primarily from Russia, the Persian Gulf region, Norway, and North Africa.

ENERGY USE AND CARBON EMISSIONS

The 15 EU countries collectively emitted 915 million metric tons (Mmt) of carbon from the consumption of fossil fuels in 1999. This accounted for 15% of world carbon emissions in that year. Of the EU countries, Germany emitted the most carbon (230 Mmt), followed by the United Kingdom (152 Mmt), Italy (121 Mmt) and France (109 Mmt). Overall, the EU emitted 2.4 metric tons of carbon per person in 1999, compared to a U.S. average of 5.6 metric tons per person. Under the December 1997 Kyoto Protocol, the EU is obligated to reduce its greenhouse gas emissions 8% from 1990 levels (in that year, the EU emitted 913 Mmt of carbon) by 2008-2012. All EU member states signed the Kyoto Protocol on April 29, 1998. On June 17, 1998, the EU agreed on how it would meet the 8% reduction. Under this agreement, different EU member states are assigned varying degrees of emission cuts, ranging from a 4% increase in the case of Sweden, to a reduction of 28% in the case of Luxembourg, with other countries somewhere in between.

Table 1. Economic and Demographic Indicators for EU Countries

	Gross Domestic Product (GDP) (purchasing power parity)				Population, 2001E (Millions)
	2000E (Billions of U.S. Dollars)	Real GDP Growth Rate		Per Capita, 2000E(U.S. Dollars)	
		2000 Estimate	2001 Projection		
Austria	$203	3.1%	2.6%	$25,000	8.2
Belgium	$259.2	4.1%	2.5%	$25,300	10.3
Denmark	$136.2	2.8%	2.2%	$25,500	5.4
Finland	$118.3	5.6%	4%	$22,900	5.2
France	$1,448	3.1%	2.7%	$24,400	59.6
Germany	$1,936	3%	2.4%	$23,400	83
Greece	$181.9	3.8%	3.9%	$17,200	10.6
Ireland	$81.9	9.9%	8.4%	$21,600	3.8
Italy	$1,273	2.7%	2.5%	$22,100	57.7
Luxembourg	15.9	5.7%	5.5%	$36,400	0.4
Netherlands	$388.4	4%	3.2%	$24,400	16
Portugal	$159	2.7%	2.8%	$15,800	10
Spain	$720.8	4%	4.4%	$18,000	40
Sweden	$197	4.3%	2.8%	$22,200	8.9
United Kingdom	$1,360	3%	2.4%	$22,800	59.6
Total	**$8,478.6**	**3.3%**	**2.8%**	**$22,446**	**378.7**

Source: CIA, WEFA World Economic Outlook.

Table 2. Energy Consumption and Carbon Emissions in EU Countries, 1999

	Energy Consumption								Carbon Emissions (Million metric tons)
	Total (Quadrillion Btu)	Petroleum	Natural Gas	Coal	Nuclear	Hydroelectric	Other Renewable Electricity	Net Electricity Imports	
Austria	1.39	39%	22%	9%	0%	30%	1%	-1%	18
Belgium	2.61	46%	23%	12%	18%	0.1%	0.4%	0.3%	38

Denmark	0.89	53%	23%	22%	0%	0.03%	5%	-3%	17
Finland	1.31	34%	11%	11%	17%	10%	8%	9%	13
France	10.26	41%	14%	6%	38%	7%	0.2%	-6%	109
Germany	13.98	41%	21%	23%	12%	1%	1%	0.1%	230
Greece	1.28	63%	4%	29%	0%	4%	0.3%	0.1%	26
Ireland	0.56	62%	23%	12%	0%	2%	0.5%	0.4%	10
Italy	8.04	51%	30%	6%	0%	6%	1%	5%	121
Luxembourg	0.19	49%	15%	2%	0%	2%	0.4%	31%	2
Netherlands	3.85	45%	40%	8%	1%	0.03%	1%	5%	64
Portugal	1.02	68%	8%	15%	0%	7%	1%	-1%	17
Spain	5.23	57%	11%	14%	11%	5%	1%	1%	82
Sweden	2.20	34%	1%	4%	30%	33%	1%	-4%	16
United Kingdom	9.92	35%	35%	16%	11%	1%	1%	%	152
Total	**62.73**	**44%**	**22%**	**13%**	**14%**	**5%**	**1%**	**0.4%**	**915**

Source: Energy Information Administration *Note: Percentages may not add to 100% due to independent rounding.*

Table 3. Energy Supply Indicators--EU Countries

	Fossil Fuel Proved Reserves			Fossil Fuel Production, 1999				
	Crude Oil, 1/1/01(Million barrels)	Natural Gas, 1/1/01 (Trillion cubic feet)	Coal (Billion short tons)	Oil (Crude, liquids, and processing gain; Thousand barrels/day)	Natural Gas (Trillion cubic feet)	Coal (Million short tons)	Electric Generating Capacity, 1/1/99 (Million kilowatts)	Crude Oil Refining Capacity, 1/1/01 Thousand barrels/day)
Austria	86	0.9	0.0	21	0.1	1.3	14	209
Belgium	0	0.0	0.0	12	0.0	0.4	13	768
Denmark	1,069	3.4	0.0	304	0.3	0.0	13	176
Finland	0	0.0	0.0	0	0.0	0.0	16	200
France	145	0.5	0.1	80	0.1	6.3	108	1,895
Germany	380	11.5	73.9	132	0.8	226.1	108	2,259
Greece	10	0.0	3.2	4	0.0	67.2	9	407
Ireland	0	0.7	0.0	1	0.0	0.0	4	71
Italy	622	8.1	0.0	147	0.6	0.0	66	2,359
Luxembourg	0	0.0	0.0	0	0.0	0.0	0	0
Netherlands	107	62.5	0.5	114	2.6	0.0	14	1,204
Portugal	0	0.0	0.0	2	0.0	0.0	10	304
Spain	21	0.0	0.7	20	0.0	26.7	45	1,294
Sweden	0	0.0	0.0	0	0.0	0.0	33	423
U.K.	5,003	26.8	1.7	2,967	3.5	40.9	70	1,771

Total	**7,443**	**114.4**	**80.1**	**3,804**	**8.0**	**368.9**	**523**	**13,340**

Sources: Energy Information Administration, *Oil & Gas Journal*.

Sources for this report include: Energy Information Administration, International Energy Agency; European Union; Oil and Gas Journal.

Links to other U.S. government sites:
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